APTD-1165

PB 211 494

EVALUATION OF THE FLUIDIZED BED COMBUSTION PROCESS

Submitted to:

Office of Air Programs
Environmental Protection Agency

Contract No. CPA 70-9

By:

Westinghouse Research Laboratories
Pittsburgh, Pennsylvania

Reproduced by
NATIONAL TECHNICAL
INFORMATION SERVICE
U S Department of Commerce
Springfield VA 22151

Volume I SUMMARY REPORT

203

BIBLIOGRAPHIC DATA SHEET

1. Report No.
APTD-1165

2.

3. Recipient's Accession No.
PB-211 494

4. Title and Subtitle
Evaluation of the Fluidized Bed Combustion Process
Volume I Summary Report

5. Report Date
November 15, 1971

6.

7. Author(s)
D. H. Archer, D. L. Keairns, J. R. Hamm, et al

8. Performing Organization Rept. No.

9. Performing Organization Name and Address
Westinghouse Research Laboratories
Pittsburgh, Pennsylvania 15235

10. Project/Task/Work Unit No.

11. Contract/Grant No.
CPA 70-9

12. Sponsoring Organization Name and Address
ENVIRONMENTAL PROTECTION AGENCY
Office of Air Programs
Research Triangle Park, North Carolina 27711

13. Type of Report & Period Covered

14.

15. Supplementary Notes

16. Abstracts

This volume is a condensation of the complete report; all the technical details of the work are contained in Volume II and III. In this condensation only the most important work is described. Some of the scope and detail has been omitted to emphasize the main themes of the work and to present clearly the most important conclusions. No problems have been identified which would preclude the development of fluidized bed combustion boilers. Potential improvements in a second generation of boilers for utility applications include raising steam temperature and pressure above the present maximums -- 1050 F, 3500 psi. Pressurized combined cycle plants have the potential for further reduction of heat rate by going to higher gas turbine temperatures. Low-grade fuels can be burned. The atmospheric pressure fluidized bed oil gasification concept has been technically demonstrated with a 750 kW development gasification plant. No problems have been identified which preclude the development of atmospheric pressure oil gasification. Further development effort is required in key areas -- e.g., calcium sulfate generation for once-through operation, temperature control, sulfur recovery.

17. Key Words and Document Analysis. 17a. Descriptors

Air pollution
Combustion
Boilers
Pressure
Temperature
Coal
Fuel oil
Design criteria
Expenses

COLOR ILLUSTRATIONS REPRODUCED
IN BLACK AND WHITE

17b. Identifiers/Open-Ended Terms

17c. COSATI Field/Group 13B

ia

18. Availability Statement
Unlimited

19. Security Class (This Report)
UNCLASSIFIED

20. Security Class (This Page)
UNCLASSIFIED

21. No. of Pages
205

22. Price
$3 00

R

FORM NTIS-35 (10-70)

USCOMM-DC 40329-P71

EVALUATION OF THE FLUIDIZED BED COMBUSTION PROCESS
SUMMARY REPORT

Contract No. CPA 70-9

November 15, 1969 - November 15, 1971

Prepared for

Office of Air Programs
Environmental Protection Agency
Research Triangle Park,
North Carolina 27711

Project Officer: P. P. Turner

By

Westinghouse Research Laboratories
Pittsburgh, Pennsylvania 15235

Authors

D. H. Archer, D. L. Keairns
J. R. Hamm, R. A. Newby
W. C. Yang, L. M. Handman
L. Elikan

ib

TABLE OF CONTENTS

VOLUME I

Page

ABSTRACT i

SUMMARY. iii

INTRODUCTION 1

FLUIDIZED BED COMBUSTION BOILER CONCEPTS 5

- Fuel. 5
- Fluidized Bed Processing. 5
- Boiler Concepts 8
- Design of a Fluidized Bed Boiler System 11

PRELIMINARY SURVEYS. 21

- Market Surveys. 23
- Fossil Fuel Survey. 35
- Survey of Alternative Means of SO_2 Pollution Control. 42
- Emission Standards Survey 43

ASSESSMENT OF FLUIDIZED BED COMBUSTION 45

- Specifications. 45
  - Functional Boiler Specifications 45
  - Operating Specifications 49
  - Design Specifications. 51
- Industrial Boiler Application 53
  - Design 53
  - Controls and Instrumentation 63
  - Operation. 64
  - Performance Characteristics. 65
  - Boiler Plant Costs 67
  - Evaluation 72
- Electric Utility Application. 78
  - Pressurized Fluid Bed Boiler Power Plant Design. 80
    - System Concept. 80
    - Power Cycle Conditions. 80
    - Boiler Plant Equipment. 83
    - Auxiliary Equipment 90
    - Power Generation Equipment. 91
    - Controls and Instrumentation. 101
    - Plant Layout. 101
    - Performance 110

TABLE OF CONTENTS (Cont'd.)

Page

- Atmospheric Pressure Fluidized Bed Boiler Power Plant Design . . . 114
  - Boiler Plant Equipment . . . 114
  - Auxiliary Equipment . . . 117
  - Sulfur Removal/Recovery System . . . 118
  - Performance . . . 120
- Economics . . . 124
- Evaluation . . . 129
  - Comparison . . . 129
  - Potential . . . 136

ASSESSMENT OF ATMOSPHERIC PRESSURE FLUIDIZED BED OIL GASIFICATION . . . 139

- Specifications . . . 139
- Gasification/Desulfurization Concepts . . . 143
- Design . . . 148
- Economics . . . 153
- Evaluation . . . 158
  - Comparison Between Regeneration and Once-Through Operations . . . 162
  - Comparison with Other SO_2 Control Methods . . . 162

FLUIDIZED BED FUEL PROCESSING DEVELOPMENT PLANTS . . . 167

- Pressurized Fluidized Bed Combustion Boiler Development Plant . . . 167
- Atmospheric Pressure Oil Gasification Demonstration Plant . . . 170

CONCLUSIONS . . . 175

- Fluidized Bed Combustion Boilers . . . 175
- Atmospheric Pressure Fluidized Bed Oil Gasification . . . 178

RECOMMENDATIONS . . . 181

- Industrial Fluidized Bed Combustion Boilers . . . 181
- Utility Fluidized Bed Combustion Boilers . . . 181
- Atmospheric Pressure Oil Gasification . . . 182

REFERENCES . . . 183

ACKNOWLEDGEMENTS . . . 185

TABLES OF CONTENTS

FOR

VOLUMES II AND III

VOLUME II

PREFACE

1. ASSESSMENT OF FLUIDIZED BED COMBUSTION

PRELIMINARY SURVEYS

FLUIDIZED BED COMBUSTION DATA

- Sulfur Dioxide Removal
- Limestone/Dolomite Regeneration
- Nitrogen Oxide Minimization
- Combustion Efficiency
- Heat Transfer
- Particle Carry-Over
- Boiler Tube Corrosion, Erosion and Fouling
- Gas Turbine Erosion and Corrosion

INDUSTRIAL BOILER APPLICATION

- Design
    - System Specifications
    - Fuel and Limestone Specifications
    - Design Bases
- Boiler System Design
    - Boiler System Schematic
    - Energy and Material Balances
    - Industrial Boiler Design Concepts
    - Selected Steam Generator Design
    - Coal and Limestone Feed Systems
    - Particulate Removal System
    - Pollution Control System
    - Selection of Draft Equipment
    - Overall Design Layout
- Boiler Operation and Performance
    - Operating Procedures
    - Performance Characteristics
    - Controls and Instrumentation

- Boiler Cost
  - Capital Cost of Once-Through Dry Solid and Wet Scrubbing Industrial Fluidized Bed Boilers
  - Comparison of Capital Cost Between Fluidized Bed Boilers and Conventional Boilers
  - Comparison of Total Cost Between Fluidized Bed Boilers and Conventional Boilers
- Effect of Operating Variables on Cost and Design of Industrial Boilers
- Recommendations

ELECTRIC UTILITY APPLICATION

- Introduction
- Pressurized Fluid Bed Boiler System
  - System Concept
  - Specifications
  - Power Cycle Analysis
  - Growth Evaluation
  - Boiler Subsystem
  - Regeneration and Sulfur Recovery System
  - Auxiliary Equipment
  - Power Generation Equipment
  - Operation and Controls
  - Control and Instrumentation
  - Plant Layout
  - Plant Performance
- Atmospheric Pressure Fluidized Bed Boiler Design
  - Specifications
  - Cycle Selection
  - Alternative Concepts
  - Boiler Design
  - Regeneration and Sulfur Recovery System
  - Auxiliary Equipment
  - Control
  - Plant Performance
- Economics
  - Capital Costs
  - Energy Costs
- Evaluation
  - Comparison
  - Potential
- Recommendations

2. ASSESSMENT OF A FLUIDIZED BED OIL GASIFICATION-COMBUSTION POWER SYSTEM

INTRODUCTION

GASIFICATION/DESULFURIZATION CONCEPTS

DATA EVALUATION

- The Esso England Program
- Gasification
    - Carbon Deposition
    - Gasifier Product Analysis
- Desulfurization
- Regeneration
- Particle Carry-Over
- Metal Retention
- Burner Design
- Preliminary Results of Continuous Operation

MATERIAL AND ENERGY BALANCES

- Modes of Operation
- Design Parameters
- Temperature Control
    - Regenerative Operation
    - Once-Through Operation
- Overall Material and Energy Balances
- Power Requirements

ih

DESIGN CONCEPTS
    Retrofit Concepts
        Retrofit Location
        Boiler Performance and Boiler Modifications
    New Boilers
    Burners
    Turn-Down
ECONOMICS
    Cost Factors
    Regeneration Operation Economics--New and Retrofit
    Once-through Operation Economics--New and Retrofit
TECHNICAL EVALUATION
    Comparison Between Regenerative and Once-Through Operations
    Comparison with Other SO_2 Control Methods
    Preliminary Design Conclusions
RECOMMENDATIONS

3. FLUIDIZED BED COMBUSTION DEVELOPMENT PLANTS

DEVELOPMENT PLANT ALTERNATIVES

PRESSURIZED FLUID BED COMBUSTION BOILER DEVELOPMENT PLANT

- Objectives
- Plant Concept
- Conceptual Design
  - Flow Diagram and Material Balance
  - Equipment
  - Space Requirement
  - Power Requirement
  - Experimental Program
  - Cost Estimate
  - Development Plant Schedule

ATMOSPHERIC PRESSURE FLUIDIZED BED OIL GASIFICATION-COMBUSTION DEMONSTRATION PLANT

- Objectives
- Plant Concept
- Conceptual Design
  - Flow Diagrams
  - Equipment
  - Boiler Capacity
  - Experimental Program
  - Development Plant Cost Estimate
  - Schedule

REFERENCES

VOLUME III

APPENDICES

APPENDIX A - Electric Utility Market Survey

APPENDIX B - Industrial Boiler Market Survey

APPENDIX C - Development of Fluidized Bed Combustion Boilers

APPENDIX D - Industrial Boiler Design Report

APPENDIX E - Turndown Techniques for Atmospheric Fluidized Bed Boilers

APPENDIX F - Dynamics of Atmospheric Fluidized Bed Boilers

APPENDIX G - Optimization of Heat Trap System Cost

APPENDIX H - Pressurized Boiler Design Report

APPENDIX I - Regeneration/Sulfur Recovery System Cost

APPENDIX J - Pressurized Boiler Combined Cycle Plant Report

APPENDIX K - Atmospheric-Pressure Boiler Design Report

APPENDIX L - Burner Design Correspondence

APPENDIX M - Gas Turbine Corrosion, Erosion, and Fouling

APPENDIX N - Stack Gas Cooler Design

ABSTRACT

The effectiveness and economics of fluidized bed combustion boilers in pollution abatement and steam/power generation have been evaluated. A 250,000 lb/hr coal-fired, factory-fabricated, industrial boiler has been designed along with all of its auxiliaries. Utility boilers have been designed for operation at atmospheric pressure in conventional steam power plants and for operation at 10 atm in a combined steam and gas turbine power plant. Overall capital and operating costs have been estimated for both 300 and 600 megawatt plants.

Of all the systems studied, the pressurized fluidized bed combustion boiler operating in a combined cycle power plant appears most effective in meeting projected emission standards and in reducing total SO_2, NO_x, and particulate emissions, and most economical in power generation. Such a plant has an estimated capital cost 20% less and energy cost 10% less than a conventional utility plant with a stack gas scrubber; this plant also has the greatest potential for increased generation efficiency and reduced costs.

A fluidized bed oil gasification-desulfurization system has also been designed and evaluated as an add-on unit for reducing SO_2 emissions from utility boilers burning high-sulfur oils. The estimated capital cost of such a unit is as much as 50% less than an add-on wet scrubbing system.

It is recommended that a developmental pressurized fluidized bed boiler unit of 10 to 30 megawatt capacity be designed and constructed to provide necessary technical information for a prototype power plant.

It is also recommended that the installation of a 100 to 200 megawatt demonstration fluidized bed oil gasifier-desulfurizer at a utility site be pursued.

SUMMARY

Fluidized bed processing of high-sulfur fossil fuels is evaluated for economical steam and/or power generation within projected pollution control limits. Industrial steam generation and utility power generation concepts are assessed on the basis of preliminary design studies. Processing includes both combustion and gasification. All of the concepts use a fluidized bed composed of a limestone or dolomite for sulfur removal. In fluidized bed combustion the sulfur dioxide and nitrogen oxides are minimized during the combustion process, and the heat transfer from the burning fuel to evaporating water is facilitated to achieve a more economical boiler system. An atmospheric pressure fluidized bed boiler is essentially a replacement of a conventional boiler. Fluidized bed combustion boilers operated at elevated pressure utilize both gas and steam-turbine generators; the high-temperature, high-pressure flue gas is expanded through the gas turbine to produce approximately 20% of the power. In fluidized bed gasification a clean fuel gas with minimal sulfur and particulates is produced which can be utilized for power generation at atmospheric pressure in conventional gas-fired boilers or at elevated pressures in a gas-turbine combustor.

The following tasks were performed:

- Industrial Boiler Market Survey
- Utility Boiler Market Survey
- Industrial Boiler Preliminary Design and Costs
- Utility Boiler Preliminary Designs -- Atmospheric and Pressurized -- and Costs
- Plant Layout and Energy Generation Cost Estimates
- Fluidized Bed Combustion Boiler Development Plant Conceptual Design and Cost Estimate

Preceding page blank

- Atmospheric Pressure Oil Gasification Assessment
- Fluidized Bed Oil Gasification Demonstration Plant Conceptual Design and Cost
- Technical Consultation and Program Assistance to the Office of Air Programs.

Boiler design specifications -- capacities, steam conditions, pollutant emission restrictions, etc. -- were based on the market surveys. The scope of the design studies is summarized in the matrix on the following page.

Energy surveys indicate that power generation in the United States will increase by a factor of four; and fossil fuel usage in generation, by a factor of three in the next 20 years.

The design studies show that fluidized bed combustion can be used to meet air pollution control regulations for SO_2, NO_x, and particulates without creating other environmental problems. The economic projections are summarized in Table 1. The industrial boiler design study and evaluation indicate that the capital cost of a once-through limestone system may be reduced by 20% over a conventional spreader stoker with wet scrubbing. However, the steam costs may be competitive for a high-sulfur coal, (4%), due to the large limestone throughput required for the fluidized bed system.

Assessment of the fluidized bed oil gasification process for retrofit on existing plants indicates that SO_2, NO_x, and particulates can be effectively and economically controlled. The process may reduce the effective increase in fuel cost for pollution control 30 to 50% below wet scrubbing, low-sulfur oil, or desulfurized oil for plant capacities greater than 50%.

Research and development efforts on pressurized fluid bed combustion boilers should continue. A 10 to 30 MW development plant should be built and operated. A utility should be sought for a 100 to 200 MW fluidized bed oil gasification demonstration plant retrofit on an existing plant. Further research and development work on atmospheric pressure systems -- industrial and utility -- should be deferred at this time.

SCOPE OF FLUIDIZED BED PROCESSING DESIGN STUDIES

	PLANT SIZE AND DESIGN DETAIL	
	Coal-Fired Plants	Oil-Fired Plants
INDUSTRIAL		
Combustion		
Atm. Pressure	Coal-fired 250,000 lb steam/hr boiler with the following alternative sulfur removal/recovery systems: clean fuel, limestone calcining-wet scrubbing, dry limestone once-through, and regenerative; preliminary design and cost for each system.	Oil-fired, 250,000 lb steam/hr; cost projected from coal-fired preliminary design.
Pressurized	Concept evaluation	
UTILITY		
Combustion		
Atm. Pressure	300 MW coal-fired boiler/regenerator/S recovery system; preliminary design and cost. 600 MW coal-fired boiler/regenerator/S recovery system; cost projected from 300 MW system plant and energy costs projected.	600 MW oil-fired plant costs projected.
Pressurized	300 MW coal-fired boiler; preliminary design and cost. 600 MW coal-fired boiler design and cost projected from preliminary design, preliminary design and cost of regeneration/S recovery system, preliminary design of plant layout, plant cost, and energy cost. 10 to 30 MW development plant; proposal design and cost.	600 MW oil-fired plant costs projected.
Gasification		
Atm. Pressure	No work conducted under contract.	600 MW oil-fired gasifier/regenerator/S recovery system; conceptual design and cost estimate; 100 to 200 MW demonstration plant conceptual design and cost estimate.
Pressurized	Designs were not developed under contract.	No work conducted under contract.

TABLE 1

FLUIDIZED BED COMBUSTION SYSTEM COST SUMMARY

	INDUSTRIAL BOILER 250,000 lb steam/hr		UTILITY POWER PLANTS 635 MW 70% Load Factor Begin Construction July, 1971		
	Conventional Stoker With Wet Scrubbing	Fluidized Bed Boiler(a)	Conventional p.f. Boiler With Wet Scrubbing Throw-Away System	Fluidized Bed Boiler With Sulfur Recovery System	
				Atmospheric Pressure	Pressurized
COAL					
Capital Cost	\$7.60/lb steam/hr	\$6.10-7.40/lb steam/hr	\$337/kW	\$313/kW	\$277/kW
Steam Cost,(b) $¢/10^6$ Btu	72.00	71.50-76.00	---	---	---
Energy Cost(c), mills/kW-hr	---	---	13.40	13.12	12.12
OIL					
Capital Cost	\$4.50/lb steam/hr	\$5.25-7.00/lb steam/hr(a)	\$308/kW	\$300/kW	\$264/kW
Steam Cost,(b) $¢/10^6$ Btu	62.70	66.50-73.50	---	---	---
Energy Cost(c), mills/kW-hr	---	---	12.59	12.78	11.76

(a) Two sulfur removal systems are considered.

(b) High-Sulfur Fuel, Fuel Cost: $30¢/10^6$ Btu, No Sulfur Credit.

(c) High-Sulfur Fuel, Fuel Cost: $45¢/10^6$ Btu over life of plant, No Sulfur Credit; Capital Charges at 15%.

INTRODUCTION

The Office of Air Programs (OAP), of the United States Environmental Protection Agency, has organized and is sponsoring a fluidized bed fuel processing program. Its purpose is to develop and demonstrate new methods for utilizing fossil fuels -- particularly coal and oil -- in industrial boilers and in utility power plants. These methods should

- Meet air pollution abatement goals for SO_2, NO_x, ash and smoke emissions
- Compete economically with alternative means for meeting these abatement goals.

The following governmental and private organizations have participated in this OAP program:

Argonne National Laboratory, Chicago
U.S. Bureau of Mines, Morgantown
Consolidation Coal, Pittsburgh
Esso Research and Engineering, Linden, New Jersey
Esso Petroleum Company, Research and Development, United Kingdom
M. W. Kellogg, Piscataway
A. M. Kinney, Cincinnati
Massachusetts Institute of Technology, Cambridge
National Coal Board, United Kingdom
Pope, Evans, and Robbins, Alexandria
Westinghouse Research Laboratories, Pittsburgh.

Westinghouse has been assigned process evaluation tasks in the fluidized bed fuel processing program. These tasks have included:

- Conducting studies predicting fuel availability and usage costs; market surveys forecasting industrial boiler and utility power plant installations; and analyses projecting air pollution control improvement. The purpose of these investigations was to provide a basis for boiler design specifications -- capacities, steam conditions, pollutant emission restrictions, etc. -- and to determine the possible beneficial improvements in environmental and economic impact of various improved steam/power generation processes.

- Designing an industrial fluidized bed boiler and two utility boilers -- one carrying out combustion at one atm, the other at 10 atm pressure. All of the boilers use a limestone/dolomite sorbent in the fluidized bed for sulfur removal. Systems for regenerating and recycling the sorbent and for recovering the sulfur in useful form have also been designed. All necessary auxiliaries for the industrial boiler and complete power plant equipment for the utility boilers have also been specified so that a complete system can be visualized. The purpose of these boiler system designs is to evaluate the performance and costs of industrial boilers and utility power plants employing fluidized bed combustion. Promising areas for future development have been identified. Westinghouse has been assisted in this work by Erie City Energy, Foster Wheeler, and United Engineers. The design and evaluation process has also pointed up technical areas where more information is needed and further development is required to meet the goal of a non-polluting, economical means of producing steam/power from fossil fuels.

- Conceptualizing a fluidized bed combustion boiler development plant. Preliminary designs have been produced for a development plant which will make possible an attack on the remaining technical problems in those areas where fluidized combustion has greatest potential for reducing air pollution and for economical generation of steam/power. Preliminary estimates of the cost for such a plant have also been made.

- Providing technical consultation and assistance on the OAP fluidized bed fuel processing program, including both combustion and gasification processes. Technical and economic comparisons have been carried out on various fluidized bed fuel processing systems and various conventional means of steam/power generation. An atmospheric pressure oil gasification/desulfurization process has been assessed in detail as an adjunct to a utility boiler.

The results of the various surveys, designs, evaluations, and comparisons are presented in this three-volume report. The report identifies fluidized bed fuel processing systems which should meet both market requirements and air pollution abatement requirements and which are likely to be cheaper than alternative, conventional systems. Finally, it recommends a program for commercializing promising processes.

This volume is a condensation of the complete report; all the technical details of the work are contained in Volumes II and III. These details support the general conclusions and provide a sound basis for future work. But in this condensation only the most important work is described. Some of the scope and detail has been omitted to emphasize the main themes of the work and to present clearly the most important conclusions.

FLUIDIZED BED COMBUSTION BOILER CONCEPTS

The OAP-Westinghouse fluidized bed fuel processing study has involved the analysis of a broad range of concepts, and the implications of the program extend further still. This section explores the range of fluidized bed combustion concepts studied.

FUEL

Fuels specifically included in the Westinghouse studies are a Pittsburgh seam coal and an Aruba oil residuum. However, fluidized bed combustion has been shown effective in utilizing a much wider variety of materials -- lignite, anthracite culm,(1,2) sewage sludge,(3,4) solid wastes,(5,6) natural gas, and high ash coals whose sodium and chlorine contents make them unsuitable for use in conventional boilers.(7) Its ability to effectively use a broad range of materials gives fluidized bed fuel processing technology great versatility and wide applicability.

FLUIDIZED BED PROCESSING

Fuel is currently processed in three reactor types -- fixed bed, suspended bed, and fluidized bed. In a fixed bed reactor, gases pass through a bed of solids at a velocity sufficiently low that the solid particles are not blown from the bed and are not supported by the flowing gases. The weight of the particles rests primarily on other particles which make up the bed. A boiler with a chain grate stoker is one type of fixed bed reactor.

In a suspended bed reactor, gases flow at a sufficiently high velocity that solid particles are carried along with the gases; their weight is supported by drag forces exerted by the gases. Contact between

Preceding page blank

particles is limited to occasional collisions. A pulverized fuel boiler is one type of suspended bed reactor.

In a fluidized bed reactor, the gases flow through a bed of particles at a sufficiently high velocity to support their weight, but not high enough to carry them out of the bed. Fluidized bed combustion reactors have not yet been applied commercially as boilers. But at least five fluidized bed gasification reactors are currently under development to produce pipeline gas and/or liquid fuels from coal. Other fluidized bed processing units have been developed to produce pipeline gas from oil; and fluidized bed reactors are now used commercially in the catalytic cracking of oil, roasting of sulfide ores, incineration of oily wastes and sludges, production of organic chemical monomers, making of cement, conversion of nuclear materials for fuel elements, etc.

Fluidized bed reactors provide the following features in processing solids and gases:

- Ease and versatility in solids flow and handling. Solid materials can readily be added to or removed from fluidized beds. Gas velocities can be chosen to promote particle mixing in the bed or to cause separation between particles of different size and density.

- Rapid heat transfer. The free movement of particles in a fluidized bed promotes rapid heat transfer both within the bed and between the bed and submerged surfaces. Bed temperatures are therefore uniform and easy to control.
- Effective gas-solid contact. Because the relative velocity between gas and solids is high, exchange of mass and heat is rapid. A fluidized bed also provides a large amount of solid surface in contact with flowing gas in a relatively small volume.

In fluidized bed combustion sufficient air is added to the fuel to virtually complete the transformation of its carbon to CO_2 and its hydrogen to H_2O:

$$\left.\begin{array}{l} C + O_2 \rightarrow CO_2 \\ \\ H_2 + 1/2\ O_2 \rightarrow H_2O \end{array}\right\} \text{ Oxidation.}$$

Both these reactions produce large quantities of heat which can be absorbed by generating steam.

Sulfur in the fuel is converted primarily to SO_2. A limestone/dolomite sorbent can be utilized in fluidized bed combustion to remove this pollutant from the combustion gases:

$$\begin{pmatrix} CaCO_3 \\ CaO \end{pmatrix} + SO_2 + 1/2\ O_2 \rightarrow CaSO_4 + \begin{pmatrix} CO_2 \\ - \end{pmatrix} .$$

The $CaSO_4$ can either be disposed of as a solid waste or it can be processed to regenerate $CaCO_3$ (or CaO) sorbent and to recover sulfur as a useful product -- elemental sulfur, S, or sulfuric acid, H_2SO_4.

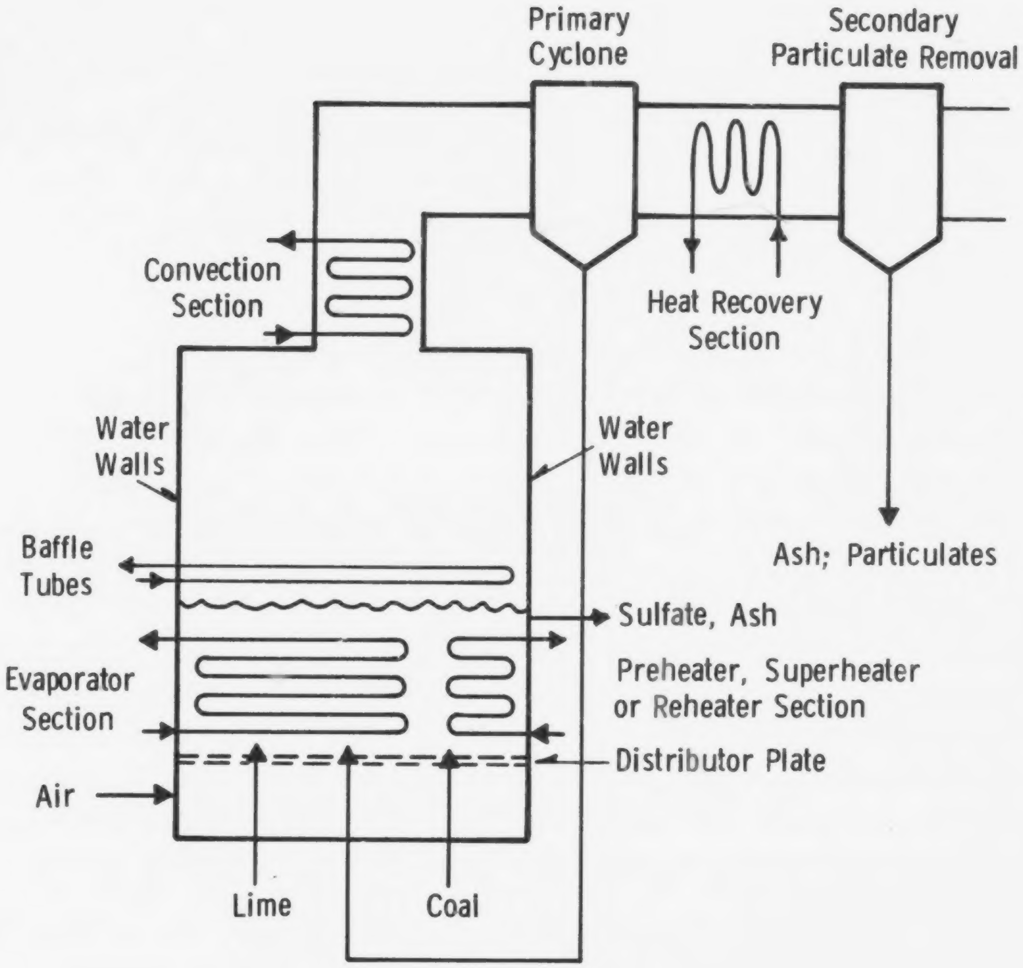
BOILER CONCEPTS

A schematic diagram of a simple coal-burning fluidized bed combustion boiler concept is shown in Figure 1. It is formed by an enclosure usually consisting of waterwalls -- abutting boiler tubes in which water and steam flow. The pressure in this enclosure is in the 1 to 25 atm range. A flat distributor plate with holes or bubble cap devices distributes the air flow uniformly over the base on the enclosure. The air then passes at velocities in the range of 2 to 15 ft/sec through a bed of particles at temperatures from 1400 to 2000°F. These particles, whose top size is 1/16 to 1/4 in., comprise ash or other inert material, lime sorbent, and small quantities (less than 1%) of unburned coal or carbon. Coal and sorbent are fed to the bed by pneumatic feeders extending through the air distributor or the waterwalls. From 60 to 70% of the heat released in burning the fuel with air is transferred to the water/steam in the tubes surrounding and submerged in the bed. Various tube configurations have been proposed -- horizontal tubes extending through the bed (Figure 2), horizontal tubes with serpentine bends in vertical platens or planes, and vertical tube walls passing up through the distributor plate, slicing the bed into narrow segments (Figure 3).

The air and combustion gases passing through the bed cause considerable agitation: particles are thrown from the bed into the empty volume above -- the freeboard. Larger, heavier particles fall back into the bed; smaller, lighter particles are carried out of the enclosure by the gases. Much of the ash in the combustion of washed coals is eventually carried from the bed in the combustion gases. Larger ash particles may accumulate in the bed and require periodic removal.

Splashing of the particles into the freeboard can be minimized by locating a screen of horizontal water/steam tubes as a baffle over the surface of the agitated bed (see Figure 1). The baffle tubes increase

Dwg. 2965A69



Pressure:	1 - 25 atm
Coal Size:	pf - 1/4 in.
Air Flow:	2 - 15 ft/sec
Temperature:	1400 - 1900 °F
Surface:	Water Walls, Horizontal, and Vertical Tubes in Bed

Sulfur removal: $CaO + SO_2 + \frac{1}{2}O_2 \rightarrow CaSO_4$

Fig. 1—Fluidized bed combustion boiler

Dwg. 2967A72

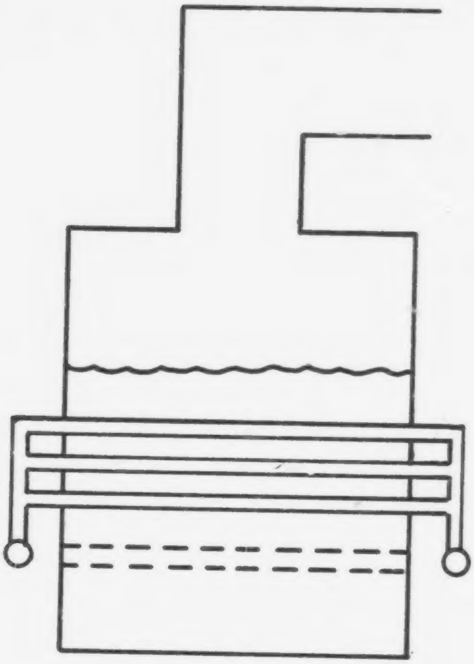


Fig. 2–Fluidized bed combustion boiler with horizontal steam tubes

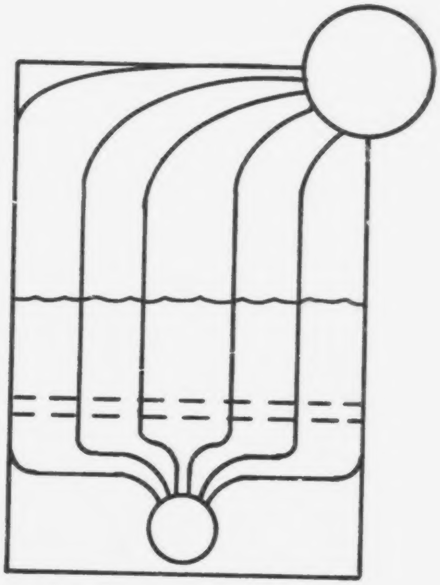


Fig. 3–Fluidized bed combustion boiler with vertical steam tubes

the heat surface exposed to the bed and reduce the height in the freeboard required to minimize the loss of large particles from the enclosure.

Convection heat transfer surface can be located in the path of the combustion products to generate more steam from the sensible heat of these gases. A reasonably high heat transfer coefficient from the combustion gases to the tube surface requires high gas velocities. These velocities can be achieved by narrowing or restricting the gas passage in the convection section (Figure 1) or by packing tubes into a broad gas passage with small clearances between tubes.

Particles carried from the fluidized bed enclosure by the combustion gases can be captured by inertial separations apparatus such as a cyclone. These particles comprise ash, fragments of the limestone/dolomite sorbent, and typically 20 to 40% by weight unburned coal char or carbon. To obtain high combustion efficiencies, the particles captured in this primary cyclone can be recycled to the boiler bed or to a separate fluidized bed combustor where the burning of the char is completed.

Additional heat can be extracted from the combustion gases in the heat recovery section, which may be either an economizer preheating boiler feed water or an air preheater.

Final clean-up of the combustion gases is carried out in a secondary particulate removal system, using cyclones or an electrostatic precipitator.

DESIGN OF A FLUIDIZED BED BOILER SYSTEM

The conceptualization of a fluidized bed boiler system involves the choice of a number of critical process operating, system configuration, and hardware design parameters.

The operating variables of greatest significance are:

- Bed temperature
- Gas velocities through the bed
- Excess air flow
- Particle diameter for the coal and sorbent
- Pressure in the combustor.

The operating bed temperature must be high enough to ignite the coal (above 750°F), to obtain reasonable combustion efficiencies in the bed (above 1400°F), to promote rapid reaction of SO_2 with the sorbent (also above 1400°F), and to attain high heat transfer rates between the bed and the tubes. But the bed temperature must also be sufficiently low to prevent sintering (below 2000 to 2100°F), to retain good sorbent reactivity (below 1600 to 1750°F), to minimize volatilization of corrosive alkali metal compounds (below 1600 to 1900°F), and to minimize corrosion/erosion of tubes in the bed. A low bed temperature is also desirable since the heat transferred by tubes in the bed is increased, thus reducing the heat transfer surface cost. Bed temperatures from 1500° to 1800°F are generally specified for fluidized bed boilers.

Gas velocity through the bed must be high enough to fluidize the particles (above 0.5 to 2.0 ft/sec at the temperature and pressure of the bed) and to obtain economical burning or heat release rates per unit area of bed (above perhaps 6 ft/sec). But gas velocities also must be low enough to avoid the loss of too many char and sorbent particles from the bed (below 15 to 20 ft/sec), to allow sufficient residence time of gases for good sulfur removal by the sorbent, to prevent too rapid attrition of the sorbent particles, and to minimize erosion of the tube surfaces.

The excess air above the stoichiometric quantity must be large enough to attain reasonably complete combustion of the fuel in the bed (5 to 10% excess air), yet small enough to minimize both the total gas flows and heat losses in the sensible heat of the stack gases.

The choice of particle size for coal and sorbent depends upon the concept of operation. One concept uses coal and sorbent with a top diameter of 1/16 to 1/8 inch -- large enough to minimize carry-over of bed particles in the combustion gases. The coal fed to the bed increases in temperature, devolatilizes, chars, and burns as it diffuses in the bed from the feed point. Some of the smaller, partially burned, char particles are carried from the bed, (elutriated), reducing somewhat the combustion efficiency of the process. The sorbent particles remove SO_2 from the combustion gases. A shell of sulphated sorbent may prevent complete utilization of the sorbent in the center of the particle. But the sorbent particles can be removed, generated, and returned to the bed; and the sulfur can be recovered in some useful form.

Another possible concept uses inert or ash particles of 1/16 to 1/4 in. diameter to constitute the bed. Both coal and sorbent are fed to the bed as particles sufficiently fine to be carried from the bed by the gases -- 100 mesh or smaller. Their residence time in the bed, however, is 10 to 100 times the gas residence time. These particles are sufficiently fine to react completely during their passage through the bed. The coal is completely burned to ash; and the sorbent is largely converted to sulfate. The ash and spent sorbent are removed from the combustion gases and collected in particle separation apparatus. The advantages of this concept over one using coarse coal and sorbent are increased combustion efficiency (no char in the carry-over from the bed) and increased utilization of the sorbent (no unsulfated core in the sorbent particles). But the use of fine particles increases greatly the difficulties in distributing fuel and sorbent uniformly over the area of the bed. The particles may well be carried from the bed or be completely reacted before spreading out from the feed point. Coarse particles have a longer residence and reaction time in the bed, and thus there is greater opportunity for achieving a uniform distribution. The use of limestone in fine particles also increases the problems involved in separating it from the combustion gases and the ash, regenerating it, and returning it to the bed.

The operating pressure of a fluidized bed combustor is a design variable which affects significantly the capacity of a boiler, the depth of the bed, and the overall power system configuration. The maximum air or combustion gas velocity through a fluidized bed combustor is limited to less than 15 to 20 ft/sec in order to prevent excessive loss of particles from the bed. The mass of air passing through the bed at any given velocity can be increased, however, by increasing the operating pressure. Since both the fuel flow and heat release rates in the combustor are generally proportional to the mass flow of air, the capacity of a boiler with a given cross-section can be increased by increasing pressure. But in order to produce more steam, more heat transfer surface must be submerged in the bed. For this reason, deeper beds will generally be required for higher-pressure fluidized bed boilers.

Operating at atmospheric pressure, a fluidized bed combustion boiler essentially replaces a conventional boiler in a power plant (see Figure 4). The power generation and auxiliary equipment is completely conventional except for the draft fans. Since the bed depth is 2 to 3 feet, the pressure loss over the fluidized bed combustor is somewhat higher than that over a conventional boiler.

Operating at elevated pressure, a fluidized combustor requires a compressor to pressurize the air and to overcome the pressure loss over the fluidized bed combustor. At an operating pressure of 10 to 15 atm and fluidizing velocity of 8 to 12 ft/sec, a depth of 8 to 15 feet is required to accommodate the heat transfer surface in the bed; the pressure loss over the bed is thus 4 to 8 times as large as that over an atmospheric bed. The pumping energy, however, is actually less because of the greater density of the gas at high pressure. Energy can be recovered from the high-temperature gases by passing them directly into a gas turbine and expanding them to atmospheric pressure as shown in Figure 5. This expansion lowers the temperature of the gases by 600 to 800°F, thereby reducing the amount of surface required to recover heat from the combustion gases leaving the fluidized bed.

The pressurized fluidized bed combustion boiler functions, therefore, in conjunction with both gas and steam turbine generators to produce electrical energy from coal or oil. In addition to the major

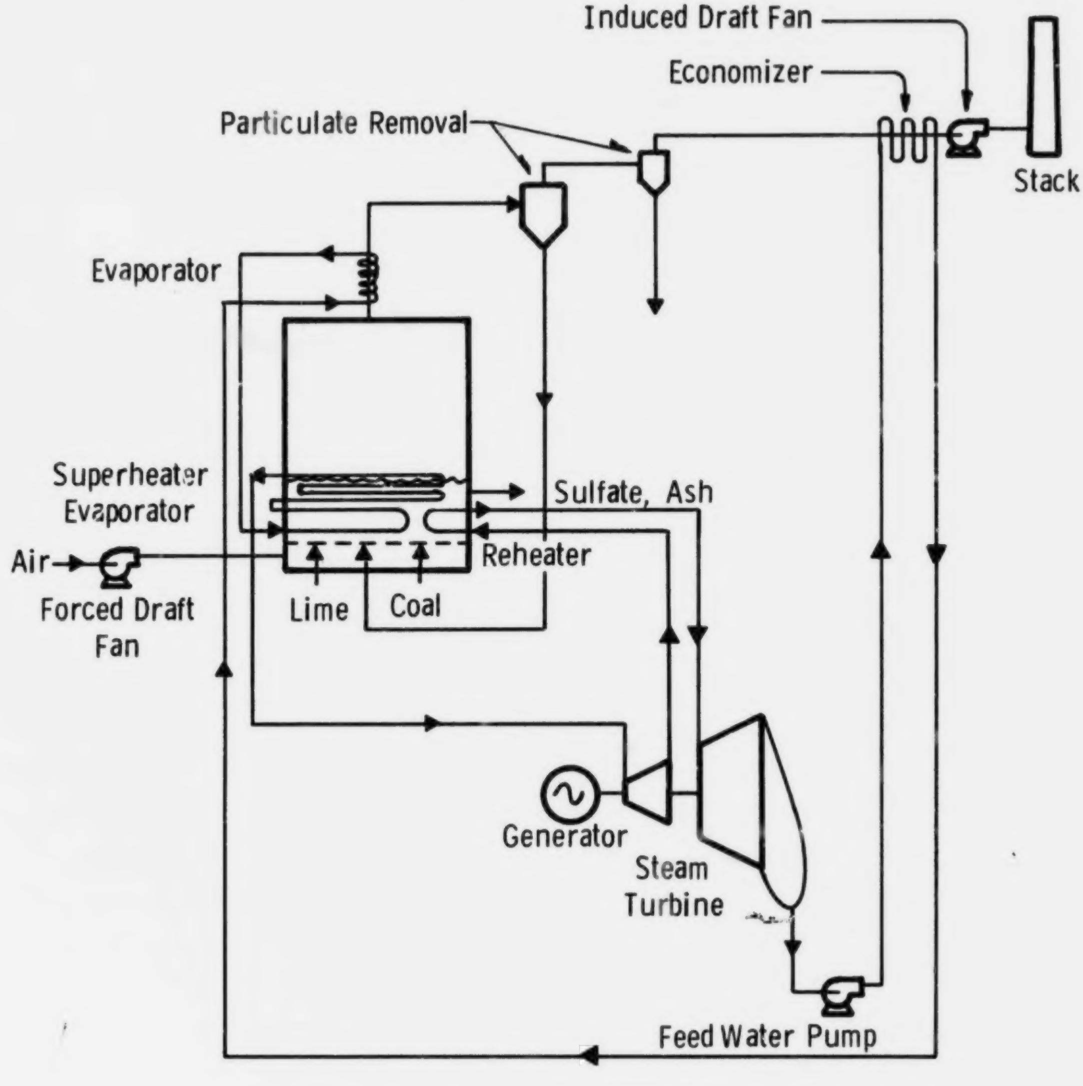


Fig. 4 –Atmospheric fluidized bed combustion power plant

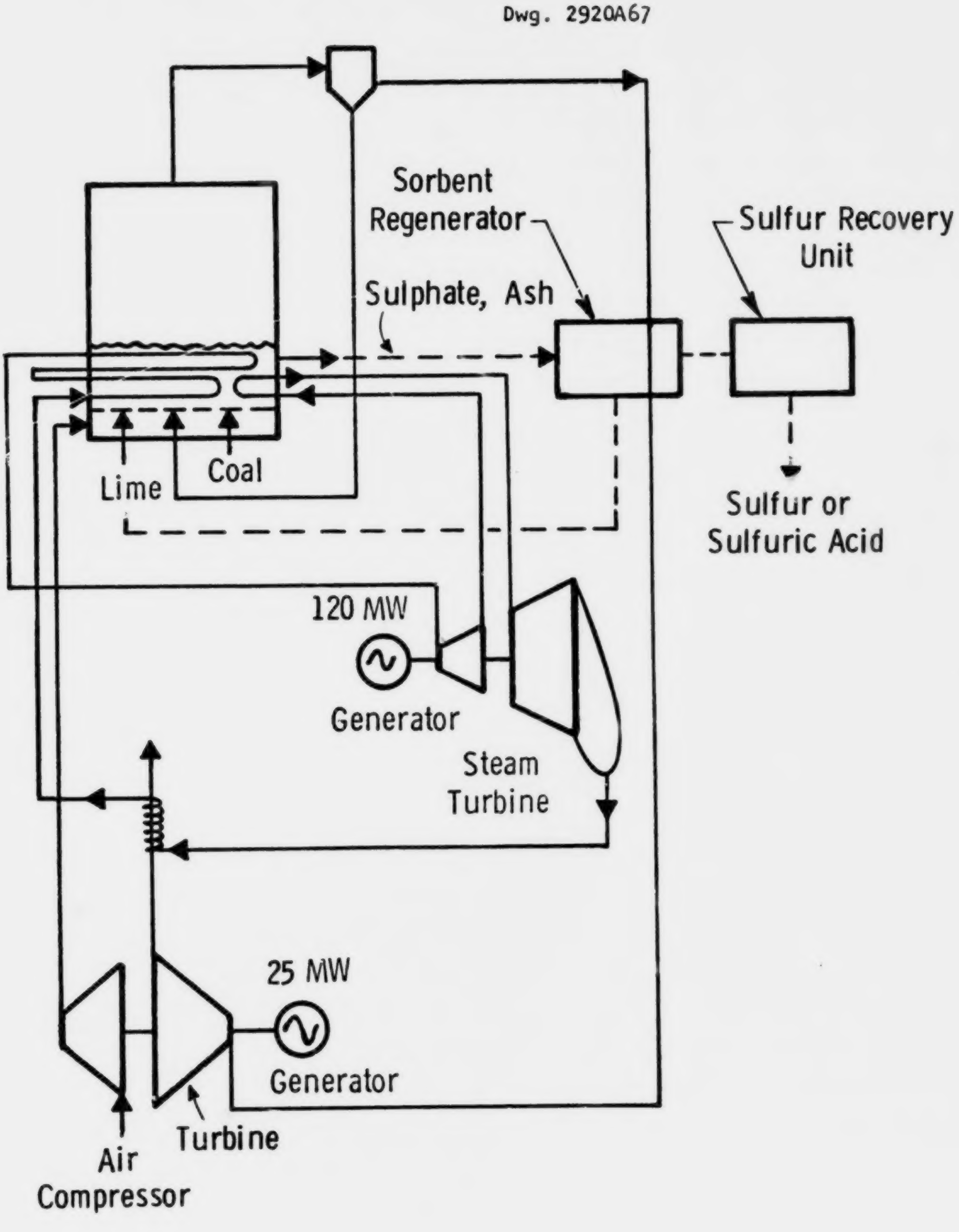


Fig. 5 — Pressurized fluidized combustion power plant

power plant equipment shown in Figure 5, additional process equipment may be included to regenerate the sorbent utilized in removing sulfur compounds from the combustion gases and to recover the sulfur in useful form either as elemental sulfur or sulfuric acid.

Along with the choice of operating variables, including pressure, and the implied choice of an overall power plant configuration, the design of a fluidized bed combustion boiler system requires the choice of a number of important hardware design parameters and features. The heat transfer tube diameter, spacing, manifolding, and orientation in the walls of the enclosure in the fluidized bed, and in the passages conveying the combustion gases from the bed, must be specified. A decision must also be made on whether baffle tubes should be incorporated to minimize the splashing of solids into the freeboard above the bed.

At the same time, the location of tubing for the various functional sections of the boiler -- pre-evaporator, evaporator, superheater, and reheater -- must be designated. And a decision is required on whether the evaporator will depend on natural circulation and employ steam drums or on forced convection; and on whether the evaporator will use recirculation or once-through flow.

The dimensions of individual fluidized beds and the orientation of multiple beds which may be employed in a large boiler are also critical design factors, primarily because of their effect on ducting and manifolding for air and combustion gases; for fuel, sorbent, and ash; and for water/steam flows.

All of these hardware parameters and features affect significantly the boiler design, its appearance, and operation. The cost of the boiler, however, probably depends more on the choice of operating variables, including pressure, than on specific hardware design.

In addition to the boiler, a fluidized bed steam/power generation system design requires the selection of auxiliary equipment, including a possible sorbent regeneration and sulfur recovery process and a layout of all plant equipment.

This report describes the design and evaluation of three fluidized bed combustion boilers. For each of these boilers, a choice of overall concept, operating variables, hardware configuration, and auxiliary equipment has been made. These choices were based on the boiler application -- whether industrial or utility -- on operability, on effectiveness, and on economics. Their justification is discussed in connection with each design.

The primary potential advantages of a fluidized bed boiler power plant are:

- Reduced volume and modular construction. Because combustion rates are more intense in fluidized beds than in the fire box of a pulverized fuel furnace, and because heat transfer surface can be placed in the bed, fluidized bed boilers are more compact than conventional coal-fired boilers. Boiler modules can be fabricated in shops and assembled at a power plant site. Considerable economies are possible in the fabrication and erection of fluidized bed combustion boilers.
- Reduced heat transfer surface requirements. Because heat transfer coefficients are an order of magnitude greater in fluidized beds than in the fire box of a conventional boiler, less heat transfer surface is required in the boiler. In a pressurized boiler less heat is extracted from the combustion gases after they leave the fluidized bed because they are cooled by expansion in the gas turbine. Further large reductions in heat transfer surface are thus possible.
- Reduced steam tube and turbine blade corrosion/erosion and fouling. Because the fluidized bed boiler operates at a maximum combustion temperature far below that in a conventional boiler, volatilization of alkali metal compounds and fusion of ash is reduced or eliminated. Sulfur and vanadium compounds are removed from the combustion gases by the sorbent. The corrosion/erosion and fouling of steam tubes and turbine blades is thus minimized. Under these conditions, higher steam temperatures and pressures may become

economically feasible and greater efficiency in power generation may be achieved. Somewhat greater efficiencies can also be achieved in pressurized fluidized bed combustion by using gas turbines with high inlet temperatures.

- Reduced fuel costs and increased flexibility. Because fluidized beds can readily burn crushed coal (fine grinding is not required), coal with a high ash content, and a variety of miscellaneous combustibles (from sewage sludge, minicipal solid wastes, paper mill liquid wastes, and oily wastes to residual oil and natural gas), boilers using such beds can utilize cheap fuels and a wide variety of fuels to generate power and steam.
- Reduced emissions of SO_2 and NO_x. Because a limestone/dolomite sorbent can be utilized in a fluidized bed combustor, SO_2 reductions of 90 to 95% can be economically achieved. The low combustion temperature at which the bed operates minimizes the formation of NO_x by fixation of atmospheric nitrogen. Production of NO_x by oxidation of nitrogen in the fuel can be minimized by limiting the percent of excess air added in the bed or by operating the bed at high pressure.

The boiler designs and performance evaluations presented in this report and the experimental work carried out under the OAP fluidized bed fuel processing program confirm these advantages of fluidized bed combustion boilers.

PRELIMINARY SURVEYS

To execute boiler designs and evaluations, market information on boiler applications as well as technical information on fluidized bed combustion had to be gathered. The market and other background data were needed to establish:

- Functional specifications as a basis for boiler (or gasifier) designs. Boiler capacity, steam conditions, efficiency, operational features such as percent turn down, and dynamic response are all established by customer requirements. In addition, fuel is chosen on the basis of availability, cost, and convenience. Finally, government regulations establish maximum levels of pollutant emissions -- SO_2, NO_x, and particulates -- for the boilers employing the selected fuel.
- A basis of comparison. The performance and cost of the fluidized bed combustion boiler systems must be compared with alternative systems in order to evaluate the likelihood of their use.
- The impact of a successful fluidized bed combustion boiler on air quality and on economical steam/power generation. The degree of impact is dependent upon how widely such boilers are used. Fluidized bed combustion can be appropriately applied to new or replacement boilers, but not to the modification of existing boilers. Thus, to justify the effort and expense of developing a new boiler technology with improved pollution abatement potential, it must be established that there is a sufficient market for new boilers.

Preceding page blank

The technical information necessary to boiler design specifications, performance, evaluations, and impact determination was obtained through the following types of surveys:

- Two market surveys: one of industrial boilers and the other of utility power plants. These surveys provided information on both past and projected boiler sales, as well as on boiler capacities and supply pressure and temperature.
- A fuel survey. This resulted in historical data on fuel usage in both industrial and utility boilers. Evidence concerning fuel availability and estimates of present and future fuel prices were also collected and examined.
- A survey of SO_2 removal systems for cleaning combustion products of conventional boilers. A number of proposed systems were evaluated as part of this survey with regard to their effectiveness and economy. A conventional boiler with a limestone wet scrubber for removal of SO_2 and particulates was then selected as a basis of comparison for the performance of the fluidized bed combustion boilers to be designed in this project.
- An emission standards survey. The government is establishing standards for limiting SO_2, NO_x, and particulate emissions from boilers. Thus, projections of what these definitive standards will be were used in setting functional specifications for the fluidized bed boiler designs.

Results of the various surveys are referenced throughout this report, but a summary of the most significant data they yielded follows:

MARKET SURVEYS

Industrial Boiler Installations

Historic data for the industrial water tube boiler market are shown in Table 2 along with boiler capacity sales predictions through 1985. Certain trends are clear:

- The total capacity of industrial boilers installed each year is increasing by about 4%.
- The number of new coal-fired installations is sharply decreasing and gas-fired installations are increasing.
- The average capacity of new boilers has increased from about 60,000 lb/hr to 75,000 lb/hr in the past seven years. Coal-fired boilers are 30% to 60% larger than the average.

The approximate operating life of an industrial boiler is 30 years. A conservatively low estimate of the existing total industrial boiler capacity is 1.2×10^9 lb/hr; the accompanying total annual fuel cost is about $2.5 billion.

The potential pollution control and economic benefits of a successful fluidized bed combustion industrial boiler are difficult to assess accurately. However, a tentative picture of the advantages of this type of boiler over other industrial boilers can be derived from several facts and observable trends. Although purchasers of industrial boilers are currently avoiding SO_2 and particulate (but not NO_x) emission problems by using natural gas or low-sulfur oil, the supplies of such fuels are limited and their costs can be expected to rise. (These points will be elaborated upon later.) In fact, it has already been announced in certain areas of the United States that there is not enough natural gas available for new industrial customers. There may, therefore, be a need for a low-cost packaged industrial boiler with a steam capacity up to 250,000 lb/hr which will burn coal in such a way

TABLE 2

ANNUAL SALES OF INDUSTRIAL WATER
TUBE BOILERS IN THE UNITED STATES

	1963	1964	1965	1966	1967	1968	1969	1970	PROJECTIONS[(a)]		
									1975	1980	1985
TOTAL CAPACITY SOLD, LB/HR x 10^{-6}	50.5	72.3	76.9	81.4	57.3	67.0	78.0	68.4	103.0	127.0	154.0
Coal-fired	10.0	14.1	12.1	5.8	4.3	4.1	2.1	2.4			
Oil-fired	12.3	16.0	17.4	18.6	11.4	15.6	13.3	17.9			
Gas-fired	20.2	29.6	34.6	45.2	34.8	39.6	47.8	39.3			
Other[(b)]	8.0	12.6	12.8	11.8	6.8	7.7	14.8	8.8			
TOTAL NUMBER SOLD	879	1033	1055	1165	839	908	1043	861			
Coal-fired	125	131	104	78	45	32	20	15			
Oil-fired	263	297	296	323	189	194	202	231			
Gas-fired	409	490	561	680	557	617	743	578			
Other[(b)]	82	115	94	84	48	65	78	37			

FOB Costs of a Packaged Industrial Boiler:

Coal--\$2.00-2.50 per lb/hr up to 60,000 lb/hr (above this field erection at \$5.50 per lb/hr without SO_2 control system).

Oil, Gas--\$2.00 per lb/hr up to 250,000 lb/hr for low sulfur fuel.

[(a)] Projections by Erie City Energy.

[(b)] Includes bagasse, black liquor, bark, waste, etc.

as to minimize SO_2, NO_x, and particulate emissions. Design work indicates that the fluidized bed boiler is indeed more compact than the conventional coal-burning boiler and thus can be packaged in sizes up to 250,000 lb/hr. And, although the estimated capital cost does not appear significantly lower than a conventional boiler system with wet scrubbing, the fluidized bed boiler is effective in pollution abatement.

Emissions of SO_2 from a fluidized bed boiler can either be reduced by a solid absorbent -- such as CaO or dolomite -- in the bed, or by using a desulfurized char fuel which may be even cheaper. Use of such a fuel would eliminate (or minimize) the use of a solid adsorbent and the problem of its disposal or regeneration. Fluidized bed combustion with staged addition of air may also be effective in reducing NO_x. Particulates may also be more readily removed from stack gases since they are generally larger than particles from pulverized fuel combustion; are not sintered so wear of cyclones and mechanical collectors should be minimized; and have a high carbon content which may improve the operation of electrostatic precipitators. Thus, fluidized bed industrial boilers may be effective and economical in air pollution control if natural gas and low-sulfur oil rise in cost and if supplies of a desulfurized char become readily available, eliminating the need to depend on a solid absorbent for pollution control.

Utility Boiler Installation

Predictions regarding utility boiler generating capacity -- total as well as for new installations -- are presented in Table 3. The new installations are further broken down into:

- Base-load plants operating with a load factor greater than 80% employing fossil fuel boilers.
- Intermediate-load plants with a load factor around 45% also operating with fossil fuels and a boiler.

TABLE 3

ELECTRIC UTILITY GENERATION ADDITIONS IN GW MARKET SUMMARY 1970-1985

	1970 TOTAL	1971-1975 ADDITIONS	1975 TOTAL	1976-1980 ADDITIONS	1980 TOTAL	1981-1985 ADDITIONS	1985 TOTAL
BASE LOAD							
Coal	87.4	10.5	97.9	30.3	128.2	2.1	130.3
Oil	21.1	1.3	22.4	4.9	27.3	-	27.3
Gas	45.5	3.4	48.9	-	48.9	-	48.9
Total Fossil	154.0	15.2	169.2	35.2	204.4	2.1	206.5
Nuclear	5.3	62.1	67.4	70.1	137.5	130.9	268.4
Hydro	25.0	-	25.0	-	25.0	-	25.0
INTERMEDIATE							
Coal	51.7	30.4	82.1	45.7	127.8	73.7	201.5
Oil	10.4	8.7	19.1	15.2	34.3	5.3	39.6
Gas	21.3	12.8	34.1	7.6	41.7	-	41.7
Total Fossil	83.4	51.9	135.3	68.5	203.8	79.0	282.8
Nuclear	-	-	-	7.6	7.6	26.3	33.9
Hydro	23.6	2.5	26.1	2.5	28.6	2.5	31.1
PEAKING							
Inter.Comb & G.T.	21.8	30.9	52.7	11.4	64.1	37.8	101.9
Hydro	7.3	15.1	22.4	18.2	40.6	15.0	55.6
TOTAL CAPACITY	320.4	177.7	489.1	213.5	711.6	293.6	1005.2

- Peaking plants operating with a load factor of less than 20% operating with gas turbines.

The most obvious market for fluidized bed combustion boilers is the one now predicted for the base- and intermediate-load fossil-fired plants; this market is expected to increase by 25% from 67 gigawatts in the period 1971 to 1975 to 81 gigawatts in 1980 to 1985. If the fluidized bed boilers are effective in air pollution control and if their capital and operating costs are sufficiently low, they may capture an additional share of the generation market now ceded to nuclear base-load plants. Higher plant efficiencies might be possible with increased steam temperature and with pressurized boilers with combined gas-steam turbine cycle.

A gigawatt of power generating capacity is roughly equivalent to 10 x 10^6 lb/hr of steam generating capacity and a coal consumption rate of 400 tons/hr. The present utility boiler market is therefore larger than the industrial boiler market by a factor of 2 in terms of capacity and by a factor of 7 in terms of money. Utility boilers also present a more serious problem in air pollution abatement. Purchasers of the smaller industrial boilers are turning to natural gas and low-sulfur oil fuels. Because of coal's low cost and availability (despite recent problems of mining it in sufficient quantities), coal remains a prime fuel for the utilities. Most of the coal available to power plants in the eastern United States has a sulfur content which exceeds the limits placed by SO_2 abatement regulations. A 1000 megawatt (1 gigawatt) plant burning 3.0% sulfur fuel produces 24 tons/hr of SO_2. A fluidized bed utility boiler which can economically absorb this pollutant (permitting the recovery of sulfur) while minimizing the production of NO_x and particulates can be greatly beneficial in reducing air pollution since about one half of the SO_2 emissions and one quarter of the NO_x emissions are attributed to electric power generation by the utilities.

Functional Boiler Specifications

In addition to examining the past and future demand for industrial and utility boilers, the market survey also considered potential customer's requirements. Figures 6 through 10 show capacity and steam conditions for future industrial and utility boiler markets.

The largest portion of the industrial boiler market will be supplied by units in the capacity range of 150,000 to 250,000 lb/hr (see Figure 6); this latter size is the largest which can be factory assembled and shipped as a package. A fluidized bed boiler can be more compact than conventional pulverized fuel boilers or a boiler with a spreader stroker. However, it is probably no more compact than conventional packaged gas- or oil-fired boilers. The steam conditions of pressure and temperature in general show a broad range of preference (see Figures 7 and 8). About two-thirds of the boilers have steam pressures below 600 psi and temperatures below 750°F.

The largest share of the fossil-fired utility boiler market will be supplied by units in the 400 to 600 megawatt range (see Figure 9); a number of waste-heat recovery boilers in the 100 to 200 megawatt range may also be purchased to operate in conjunction with gas turbines in combined cycle power plants. Both supercritical boiler units operating around 3600 psi and subcritical units operating around 2400 psi steam pressure will continue to be popular with customers (see Figure 10).

Table 4 summarizes the information on functional requirements used in establishing specifications for the industrial and utility fluidized bed boiler designs. The final designation of specifications is discussed in subsequent sections dealing with the detailed boiler designs.

Curve 594987-A

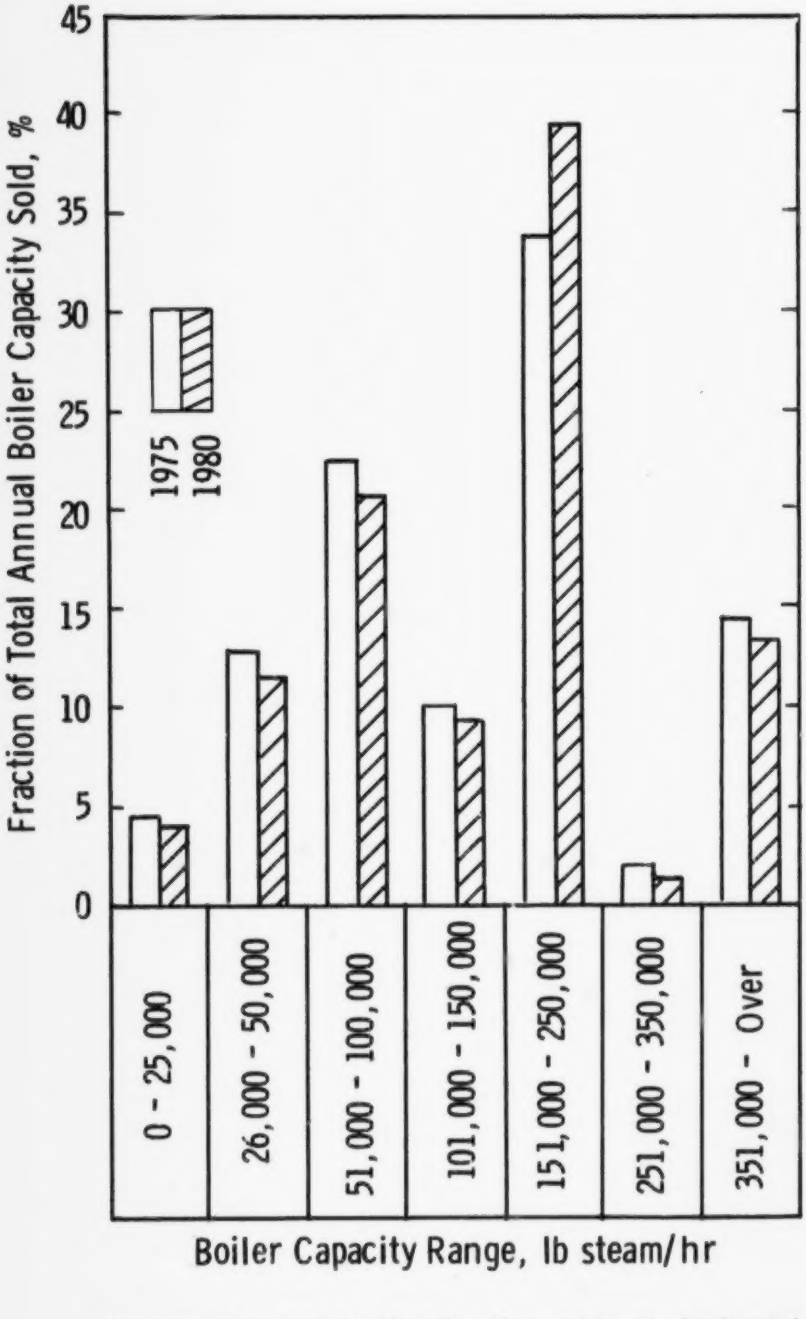


Fig. 6 —Projected distribution of U. S. industrial boiler sales - steam generating capacity

Curve 594988-A

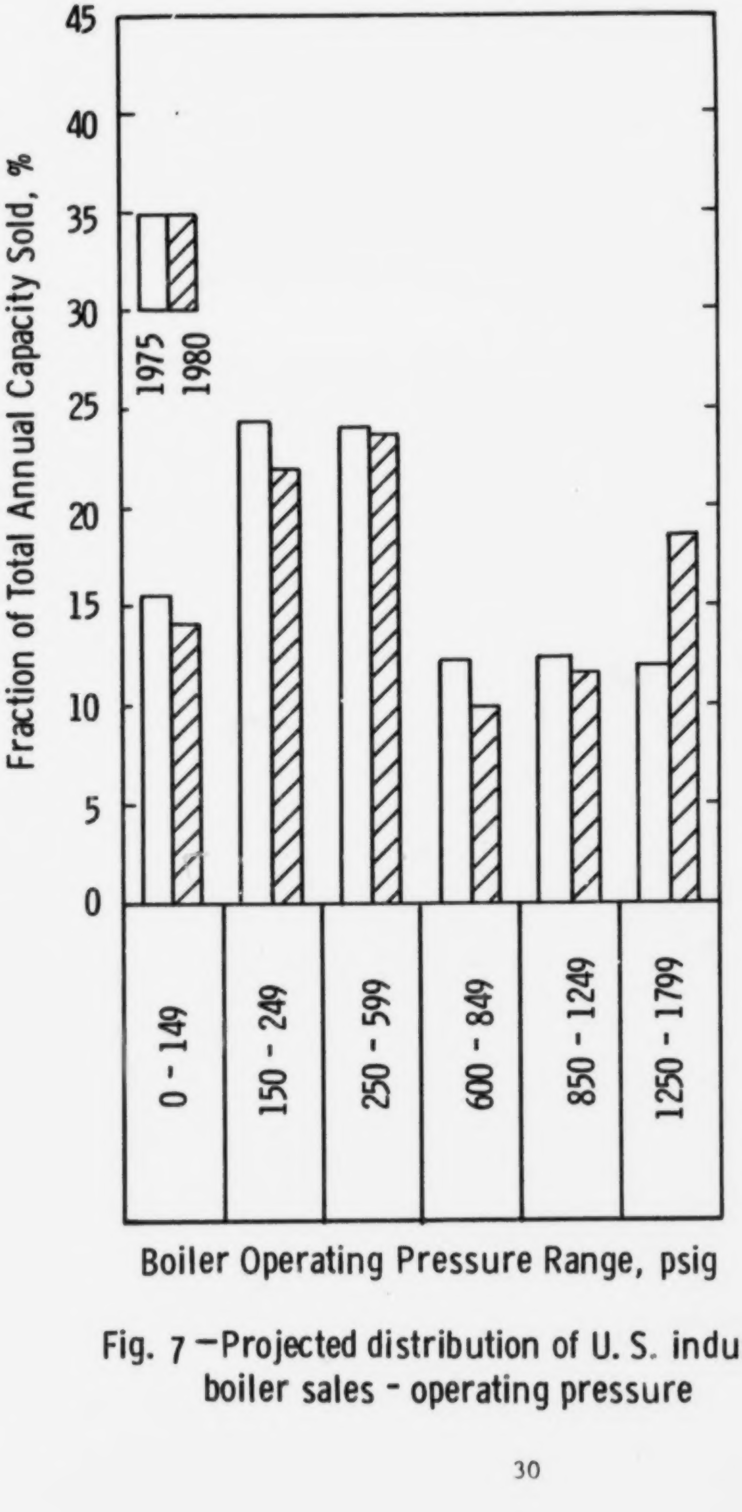


Fig. 7 —Projected distribution of U. S. industrial boiler sales - operating pressure

Curve 594989-A

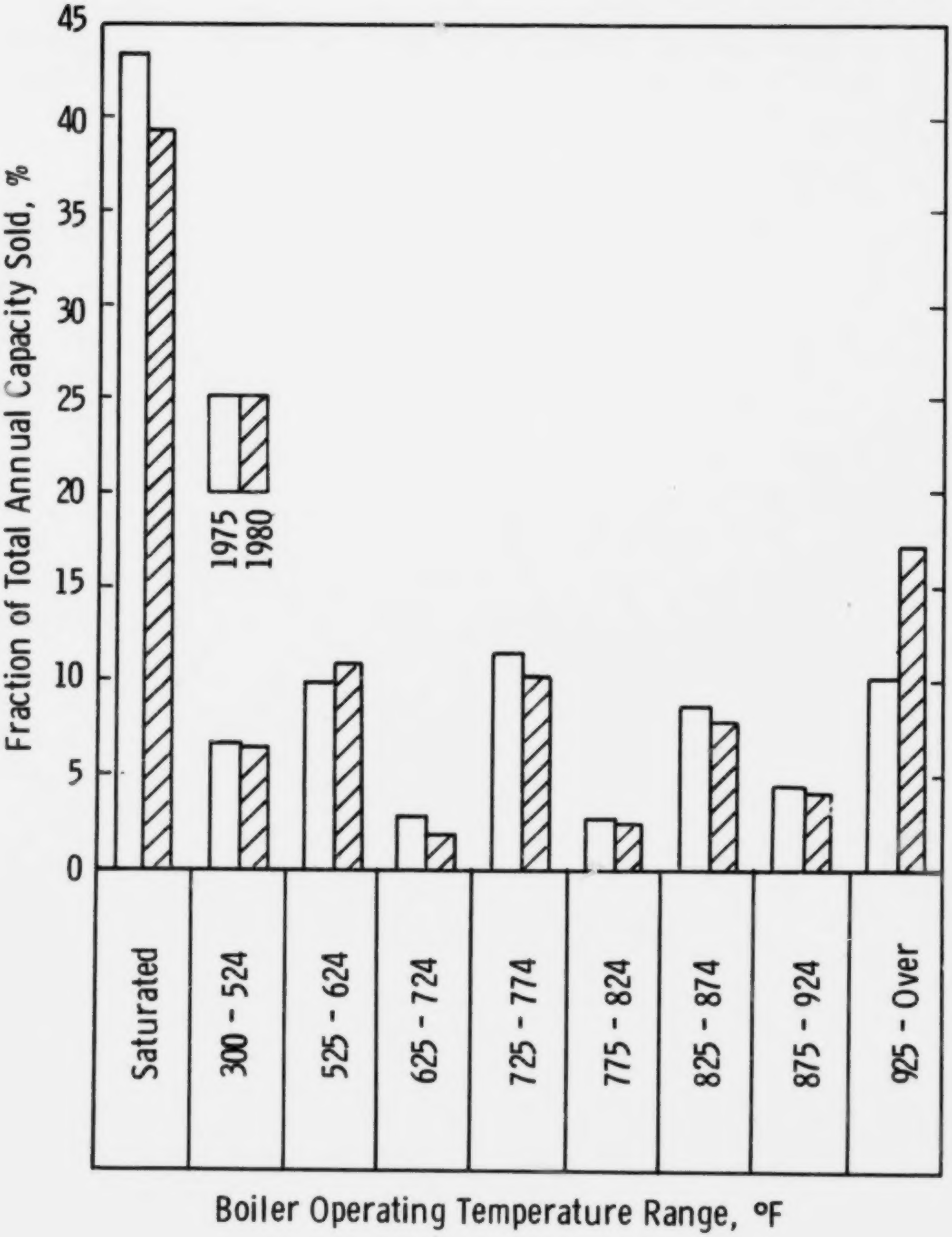


Fig. 8 —Projected distribution of U. S. industrial boiler sales - operating temperature

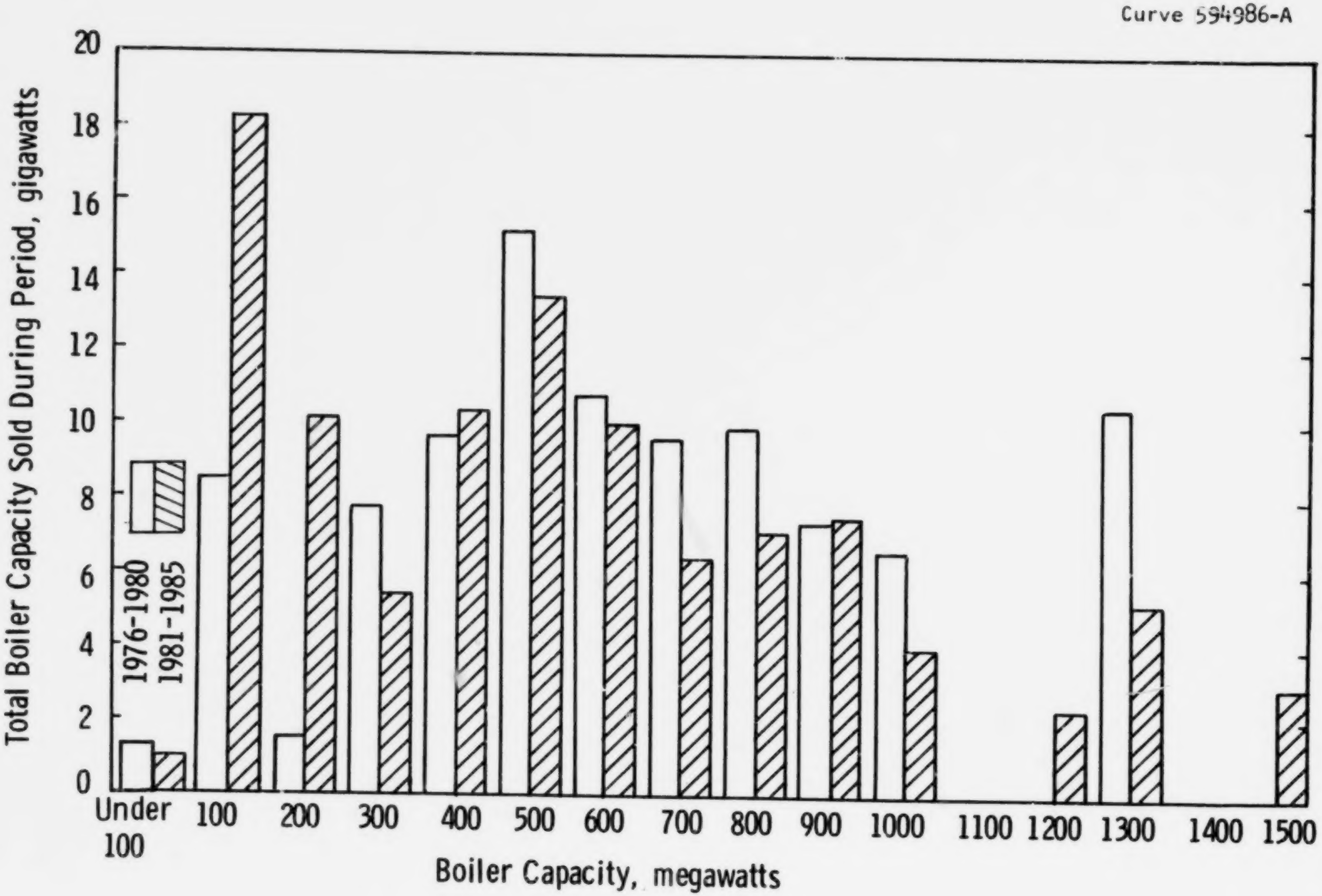


Fig. 9 —Projected U. S. utility boiler sales - steam generating capacity

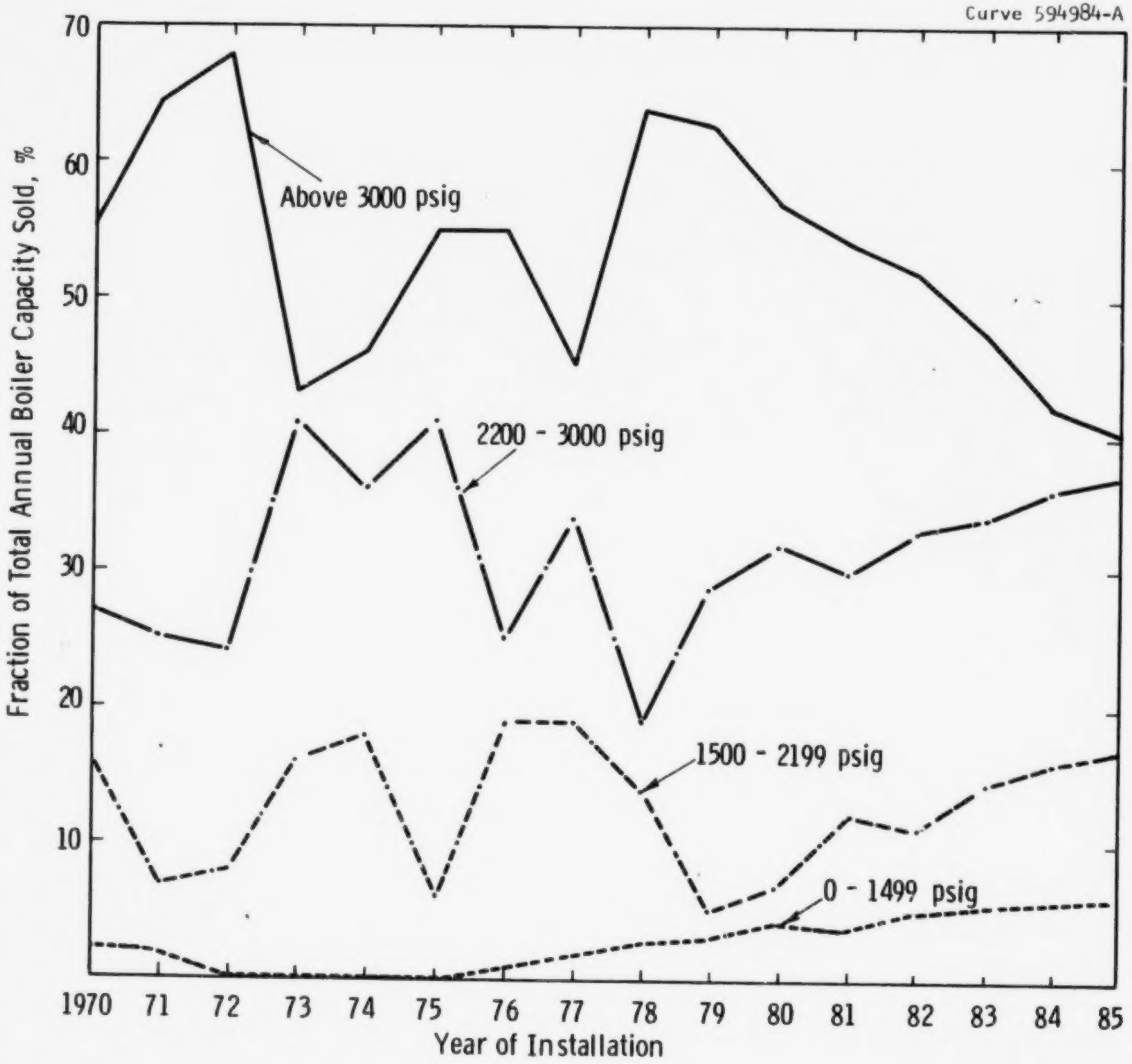


Fig. 10 —Projected distribution of U. S. utility boiler installations - steam pressure

TABLE 4

FUNCTIONAL SPECIFICATIONS FOR FLUIDIZED BED COMBUSTION BOILERS DEVELOPED BY THE BOILER MARKET SURVEY

	INDUSTRIAL BOILER	UTILITY BOILER		
CAPACITY				
Maximum	350-500 x 10^3 lb/hr	1300 MW		
Most Frequent	150-250 x 10^3 lb/hr	500-700 MW		
Minimum	25 x 10^3 lb/hr	100 MW		
STEAM CONDITIONS				
Size Range MW		< 300	500-800	< 800
Pressure psig	150-600	1800	2400	3600
Temperature °F	(sat - 775)	950/950	1000/1000	1050/1050
PERFORMANCE				
Efficiency %	86	89-92		
SPECIAL REQUIREMENTS				
Turn-down	1/3	1/4 (1/2)		
Overpressure & Flow		5% on each		
Dynamics		5%/minute		
Start-up, Shut-down		Automatic		
Pressurized Operation	No	Yes		
TV Viewing	No	Yes		
Packaged Construction	Preferred	Unfeasible at present, but desired		
Multi-fuel Capability	Not usually demanded	Desired		

FOSSIL FUEL SURVEY

The proven recoverable fuel reserves available for possible use in U. S. boilers are shown in Table 5. The actual economically recoverable reserves of these fossil fuels may be as much as 2 to 3 times the proved values. Domestic oil and gas reserves are in relatively short supply: their prices can be expected to increase especially if foreign developments hinder the free flow of oil to this country. Thus, it appears likely that industrial and utility boiler operators will ultimately be required to utilize coal or a fuel derived from coal. Coal is the most plentiful source of fossil energy. Slightly over half of the coal energy of the United States is found in deposits east of the Mississippi River, and most of this coal has a sulfur content of 2.5 to 4.0% by weight.

Predicted costs of fossil fuels are summarized in Table 6 and Figure 11. These 15-year projections are highly speculative; unexpected technological, economic, environmental, or political developments may invalidate them. The price of coal has been based on estimates of production costs for labor, materials, and equipment. Recent health and safety measures and labor unrest have decreased productivity in deep mines by an estimated 20% in the past two years, and it is difficult to assess how productivity will fluctuate in the future. It is equally difficult to assess the effects of environmental concerns on the cost of coal from strip mines. With all these uncertainties the price of coal is expected to double in the next 15 years.

The price of oil, residual or crude, for boiler fuel has been based on what the utility customer will pay for oil in competition with other fossil fuels, primarily coal.

The price of natural gas has, for many years, been based on government regulations. But now gas is a premium fuel in short supply; its exploration and development costs are rising. The production of gas from liquid petroleum products and from coal is about to commence.

TABLE 5

ENERGY RESERVES AND UTILIZATION

	U. S. RESERVES		ESTIMATED ANNUAL U. S. CONSUMPTION[a], 1968				
	Proven	Estimated Total Recoverable	Household and Commercial	Industrial	Electricity	Transportation	Total
COAL tons x 10^9	265	3200	0.02	0.21	0.27	-	0.50
PETROLEUM bbls x 10^9	46	145-590	1.2	0.8	0.2	2.5	4.7
GAS MCF x 10^9	290	850-2400	6.3	9.0	3.1	0.6	19.0

---

[a] U. S. Bureau of Mines estimate. Future consumption patterns will depend on government regulation, which may restrict the use of gas by utilities in order to meet household, commercial, and industrial clean fuel needs; oil import; environmental regulations; availability; and production costs.

TABLE 6

ELECTRIC UTILITY FUEL PRICE PROJECTIONS 1971-1985

STEAM COAL
DEEP-MINED MINE-MOUTH

Year	¢/MMBTU	Index
1968	16.7	100.00
1969	17.8	106.58
1970	21.3	127.54
1971	26.2	156.88
1972	30.0	179.64
1973	32.0	191.61
1974	33.4	200.00
1975	34.2	204.79
1976	35.3	211.37
1977	36.6	219.16
1978	37.9	226.94
1979	39.2	234.73
1980	40.6	243.11
1985	48.6	291.01

RESIDUAL OIL
DEEP WATER PORT CONTRACT CARGOS
(1968 High Sulfur Resid. Price = 100.00)

	High Sulfur Resid.		Low (1%) Sulfur Resid.		0.3% Sulfur Resid.	
Year	¢/MMBTU	Index	¢/MMBTU	Index	¢/MMBTU	Index
1968	32.0	100.00				
1969	34.0	106.25				
1970	46.0	143.75	72.0	225.00		
1971	43.0	134.37	60.0	187.50	75.0	234.37
1972	43.5	135.93	61.0	190.62	76.0	237.50
1973	44.0	137.50	64.0	200.00	78.0	243.75
1974	44.5	139.06	67.0	209.37	82.0	256.25
1975	45.0	140.62	70.0	218.75	85.5	267.18
1976	45.5	142.18	72.0	225.00	88.5	276.56
1977	46.0	143.75	73.0	228.12	90.0	281.25
1978	46.5	145.31	74.0	231.25	91.0	284.37
1979	47.0	146.87	74.5	232.81	92.0	287.50
1980	47.5	148.43	75.0	234.37	93.0	290.62
1985	50.0	156.25	77.0	240.62	94.5	295.31

TABLE 6 (cont'd.)

CRUDE OIL
DEEP WATER PORT CONTRACT CARGOS
(1971 High Sulfur Crude Price = 100.00)

	High Sulfur Crude		Low (1%) Sulfur Crude		0.3% Sulfur Crude	
Year	¢/MMBTU	Index	¢/MMBTU	Index	¢/MMBTU	Index
1968						
1969						
1970						
1971	50.0	100.0	56.0	112.0	72.5	145.0
1972	51.5	103.0	58.0	116.0	75.0	150.0
1973	53.0	106.0	59.5	118.0	77.0	154.0
1974	54.5	109.0	61.5	123.0	79.5	159.0
1975	55.5	111.0	63.5	127.0	82.0	164.0
1976	57.0	114.0	65.5	131.0	84.0	168.0
1977	58.5	117.0	67.0	134.0	86.0	172.0
1978	60.0	120.0	68.5	137.0	87.5	175.0
1979	61.0	122.0	69.5	139.0	88.5	177.0
1980	62.5	125.0	70.5	141.0	89.5	179.0
1985	69.5	139.0	76.0	152.0	93.0	186.0

NATURAL GAS
ELECTRIC UTILITY PRICE

Year	¢/MMBTU	Index
1968	25.1	100.00
1969	25.4	101.19
1970	27.0	107.56
1971	35.0	139.44
1972	45.0	179.28
1973	55.0	219.12
1974	65.0	258.96
1975	72.0	286.85
1976	77.0	306.77
1977	80.0	318.72
1978	83.0	330.67
1979	85.0	338.64
1980	87.0	346.61
1985	97.0	386.45

Curve 645771-A

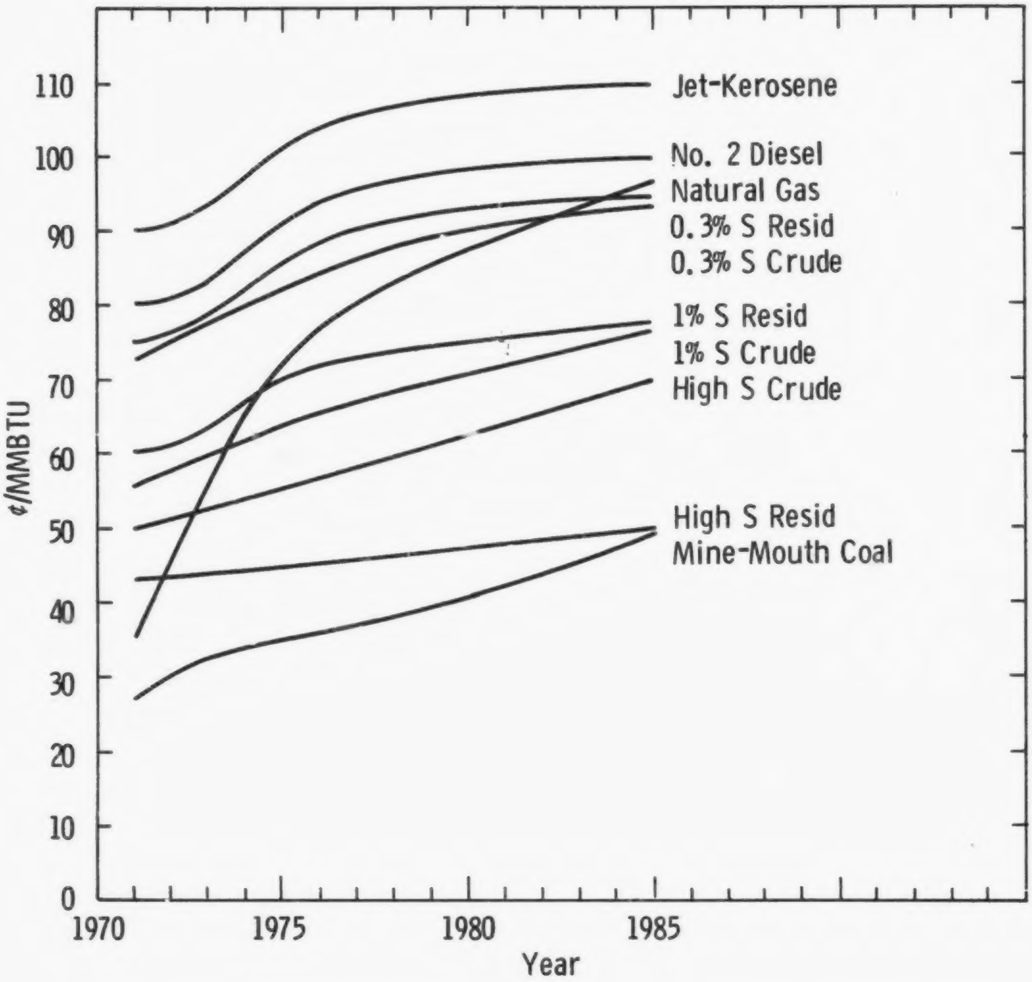


Fig. 11 — Electric utility fuel price projections 1971—1985 actual dollars

Importation of liquified natural gas is being considered. For these reasons gas costs are expected to rise sharply in the next 15 years, and gas may not be available to the operators of large industrial or utility boilers.

Transportation costs for fuels are given below in Table 7. These indicate that coal and gas cannot be used economically in large utility boilers distantly located from the source of supply.

TABLE 7

COMPARATIVE TRANSPORTATION COSTS
FOSSIL FUELS FOR ELECTRIC UTILITIES

COAL --	UNIT TRAIN		
	Under 300 Miles	-	∿4.00¢/million Btu/100 miles
	Over 600 Miles	-	∿2.00¢/million Btu/100 miles
GAS --	48" PIPELINE	-	1.50¢/million Btu/100 miles
RESIDUAL OIL			
	Large Tankers	-	0.30¢/million Btu/100 miles
	Large River Barges	-	0.60¢/million Btu/100 miles

A careful consideration of all the technical, economic, and political factors involved in the choice of fuel supply indicates that utilities will use fossil fuels for generating about 60% of the electric power in 1985 as seen in Table 8. Although it is much more difficult to predict what type of fuel will be preferred for industrial boilers, it seems likely that most operators will continue to use clean fuels, gas, and low-sulfur oil. In all cases, however, a vital factor in the choice of fuels and the economics of steam and power generation will be pollution abatement.

TABLE 8

PROJECTED ELECTRIC ENERGY PRODUCTION BY STEAM: RELATIVE SHARE ACCORDING TO FUEL

FUEL	RELATIVE SHARE OF ELECTRIC UTILITY STEAM GENERATION									
	1969		1970		1975		1980		1985	
	KWH x 10^9	%	KWH x 10^9	%	KWH x 10^9	%	KWH x 10^9	%	KWH x 10^9	%
COAL	793.1	60.9	858.8	60.1	1101.7	50.0	1252.5	42.3	1396.1	34.4
GAS	354.6	27.2	371.5	26.0	461.7	21.0	536.0	18.1	625.4	15.4
OIL	135.3	10.4	135.7	9.5	177.6	8.1	239.5	8.1	394.5	9.7
FOSSIL	1283	98.5	1366	95.6	1741	79.1	2028	68.5	2416	59.5
NUCLEAR	19	1.5	63	4.4	461	20.9	933	31.5	1648	40.5
TOTAL	1302	100	1429	100	2202	100	2961	100	4064	100

SURVEY OF ALTERNATIVE MEANS OF SO_2 POLLUTION CONTROL

A number of stack gas processing systems have been proposed for SO_2 removal. Current first-generation processes evaluated were Combustion Engineering's dry lime wet scrubbing process, Chemico's wet scrubbing process, and Monsanto's catalytic oxidation process. Second generation processes were also considered: Wellman Power Gas, Esso-B&W dry adsorbent, Consolidation Coal potassium formate, Stone & Webster-Ionics electrolysis, and Atomics International molten carbonate. These systems have been considered for possible use in electric power plants with conventional coal-fired boilers. Some of these systems are either ready, or nearly ready, for commercial application; some require additional development and testing.

In general, the capital costs of the systems are comparable to the cost of the utility steam generator itself -- $35/kW. Most of the processes claim the 80 to 90% SO_2 removal required by today's air pollution abatement goals. However, it is not clear how many of them can economically accomplish the 90 to 98% removal which may be required as the use of coal in power generation increases. The lime/limestone wet scrubbing processes have received the major development effort. A number of units are being tested on full-scale power plants.(8) Capital costs range from $20 to $50/kw for new plants and from $40 to $80/kw for retrofit on existing plants. Operating costs are projected to be from 0.3 to greater than 1 mill/kw-hr. These costs are for 60 to 80% SO_2 removal. Alternative systems, e.g., Monsanto catalytic oxidation, are reported to be more expensive.

These stack gas clean-up processes are unlikely to be economical for industrial boilers. Scaled down to a size corresponding to a 250,000 lb/hr steam boiler, their cost would be in the range of $1.50 to $3.00 per lb/hr, greater than the cost of the boiler itself.

If fluidized bed combustion boilers are more effective in air pollution control and lower in cost than conventional boilers plus stack gas clean-up equipment, then they may well capture a sizeable portion of the predicted market.

EMISSION STANDARDS SURVEY

Federal New Source Performance Standards reflect the degree of emission reduction which (taking into account the cost of achieving such reduction) the Administrator of EPA determines has been adequately demonstrated. The Standards of Performance for fossil fuel-fired steam generators of greater than 250 million Btu per hour heat input have been promulgated and in part are as follows:

SO_2	1.2 lb $SO_2/10^6$ Btu	(solid fossil fuel)
	0.8 lb $SO_2/10^6$ Btu	(liquid fossil fuel)
NO_x	0.70 lb $NO_2/10^6$ Btu	(solid fossil fuel)
	0.30 lb $NO_2/10^6$ Btu	(liquid fossil fuel)
	0.20 lb $NO_2/10^6$ Btu	(gaseous fossil fuel)
Particulate	0.1 lb/10^6 Btu	(all fossil fuels).

However, looking to the future, the ultimate goal of control achieved by any advanced fuel processing concept must be aimed toward higher levels of control, which (looking to the future) will be consistent with the meeting of Ambient Air Quality Standards in all Air Quality Regions without necessarily restraining the growth capacity of power required for the area. A second goal is that the advanced technology have reduced costs so that higher levels of control can be possible at a lower power cost than present-day power plants with present-day control. It is reasonable that such advanced technology would be applied to enhancing the present Federal New Source Performance Standards.

As a first basis for design of the coal-fired fluid bed combustion power plants the following criteria were used:

SO_2	$\leq$	1 lb $SO_2/10^6$ Btu
NO_x		0.2 lb $NO_2/10^6$ Btu
Particulate		down to 0.02 lb/10^6 Btu.

The emission criteria include all emission sources from the power plant: coal drying, boiler, sorbent regeneration and sulfur recovery.

ASSESSMENT OF FLUIDIZED BED COMBUSTION

Specifications and design concepts were established for industrial and utility fluidized bed combustion boilers. Preliminary designs, performance projections, and cost estimates were prepared on the basis of the specifications and compared with conventional systems.

SPECIFICATIONS

The design specifications for industrial and utility fluidized bed combustion boilers are based on

- Market requirements
- Environmental control requirements
- Fluidized bed combustion experimental data
- Related technology experience.

Functional, operating, and design specifications are established. They represent an assessment of present information to provide constraints and a basis for reasonable first-generation designs. However, they must be viewed flexibly since data are not available to permit optimization of the parameters. The specifications do not incorporate advanced functional, operating or design characteristics which are considered feasible for more economical second-generation designs.

Functional Boiler Specifications

Functional specifications for industrial and utility boilers are based on the market survey results, the projected environmental control requirements, and power cycle studies. The functional specifications for an industrial boiler, an atmospheric pressure utility boiler, and a pressurized utility boiler are summarized in Table 9. The limestone and dolomite analyses are presented in Table 10 below

TABLE 9

FUNCTIONAL SPECIFICATIONS FOR FLUIDIZED BED COMBUSTION BOILERS

	INDUSTRIAL	ATMOSPHERIC PRESSURE UTILITY	PRESSURIZED UTILITY
CAPACITY	250,000 lb steam/hr	300 & 600 MW	300 & 600 MW
STEAM CONDITIONS	600 psig/750°F	2400 psig/1000°F/1000°F	2400 psig/1000°F/1000°F
GAS TURBINE	---	---	Simple cycle with 10:1 pressure ratio without compressor intercooling
FUEL	Pgh. #8 bituminous coal 4.3% S	Pgh. #8 bituminous coal 4.3% S	Pgh. #8 bituminous coal 4.3% S
SO_2 REMOVAL AGENT	Limestone 1359	Limestone 1359	Dolomite 1337
TURNDOWN CAPABILITY	$\geq$ 4:1	$\geq$ 4:1	$\geq$ 4:1
RESPONSE RATE, %/MIN	$\geq$ 5	5	5
POLLUTION ABATEMENT TARGETS			
Sulfur Dioxide, lb $SO_2/10^6$ Btu	$\leq$ 1	$\leq$ 1	$\leq$ 1
Nitrogen Oxides, lb $NO_2/10^6$ Btu	$\leq$ 0.2	$\leq$ 0.2	$\leq$ 0.2
Particulate, lb/10^6 Btu	< 0.1 down to 0.02	< 0.1 down to 0.02	< 0.1 down to 0.02
SO_2 REMOVAL SYSTEM	Once-through	Regeneration and once-through	Regeneration and once-through
BOILER EFFICIENCY, %	$\geq$ 85	88-92	88-92

and in the coal specification list on the following page.

TABLE 10

LIMESTONE AND DOLOMITE SPECIFICATIONS

COMPONENT	WT % AS RECEIVED*	
	Dolomite 1337	Limestone 1359
SiO_2	0.78	0.85
Al_2O_3	0.15	0.30
Fe_2O_3	0.25	0.17
MgO	45.0	1.07
CaO	53.0	97.0
TiO_2	0.02	<0.05
SrO	<0.03	0.07
Na_2O	<0.02	<0.02
K_2O	<0.1	<0.1
MnO_2	<0.03	<0.05

*Coutant, R. W., J. S. McNulty, R. E. Barrett, J. J. Carson, R. Fisher, and E. H. Lougher; "Investigation of the Reactivity of Limestone and Dolomite for Capturing SO_2 from Flue Gas," Aug. 1968 (Battelle Memorial Institute).

The capacity and steam conditions are based on the market survey projections and technical assessments. A high-sulfur bituminous coal was selected as the fuel. This fuel is representative of coals used in the fluidized bed combustion experimental program and of coal-fired power plants, except for the high sulfur content. A limestone and a dolomite sorbent were selected for the designs. The two stones have been used in the experimental fluidized bed combustion programs. The boiler turndown capability of 4:1 is specified on the basis of the market survey. The pollution abatement targets are based on projected control requirements for SO_2, NO_x, and particulates. Once-through limestone or dolomite throw-away and regenerative/sulfur recovery processes are considered for the sulfur removal system. The industrial boiler designs incorporate once-through processes. Both concepts are considered for the utility boilers. Boiler efficiency targets are specified, based on current coal-fired boiler capability.

COAL SPECIFICATION
OHIO PITTSBURGH NO. 8 SEAM COAL*

SAMPLE: Run of Mine - As Received (washed)

PROXIMATE ANALYSIS (wt %):

Moisture	3.3
Volatile Matter	39.5
Fixed Carbon	48.7
Ash	8.5
	100.0

ULTIMATE ANALYSIS (wt %):
(includes moisture)

C	71.2	
H	5.4	
O	9.3	
N	1.3	
S	4.3	(~60% organic; ~40% pyritic)
Ash	8.5	
	100.0	

GROSS HEATING VALUE: 13000 Btu/lb

NET HEATING VALUE: 12500 Btu/lb

ASH ANALYSIS (wt %):

SiO_2	45.3
Al_2O_3	21.2
Fe_2O_3	27.3
TiO_2	1.0
P_2O_5	0.11
CaO	1.9
MgO	0.6
Na_2O	0.2
K_2O	1.8
SO_3	0.7
	100.1

FUSIBILITY OF ASH:

Initial Deformation Temperature	-- 2080°F
Softening Temperature	-- 2230°F
Fluid Temperature	-- 2420°F

PARTICLE DENSITY:

Coal -- ~1.4 gm/cc
Ash -- ~2.8 gm/cc

GRINDABILITY (Hardgrove): 50-60

FREE SWELLING INDEX: 5-5.5

---

*Source of data: USBM, Pittsburgh, Pa.

Operating Specifications

Operating conditions for the fluidized bed combustion boilers were projected from available data(9). The conditions are summarized in the following specifications list.

OPERATING SPECIFICATIONS
FOR FLUIDIZED BED COMBUSTION BOILERS

PRESSURE, ATM	1 and 10
BED TEMPERATURE, °F	
Primary beds	1300-1750
Carbon burn-up cell	1900-2000
GAS VELOCITY, fps	5-15
PARTICLE SIZE, INCHES	≥ - 1/4
EXCESS AIR, %	
Primary beds	10
Carbon burn-up cell	≥ 30
BED DEPTH -- EXPANDED, FT	
Atmospheric pressure	≤ ~5
Pressurized	≤ ~
Ca/S RATIO	6

Pressure: Atmospheric pressure and pressurized operation are considered. Ten atmospheres is used for the pressurized system to correspond to state-of-the-art gas turbine technology.

Bed Temperature: The range of temperature for the primary bed is limited by sulfur dioxide removal. The carbon burn-up cell temperature is established to achieve high carbon burn-up, ≥ 90%.

Gas Velocity: Fluidized bed combustors have operated at superficial gas velocities up to 15 fps. Higher velocities are considered feasible and desirable to achieve compactness and minimize coal distribution problems. However, they result in higher particulate carry-over, the need for larger particles -- which affects tube spacing design in the bed, and lower limestone/dolomite utilization. Gas velocities greater than 2 to 5 fps are necessary to minimize the cross-sectional area of the beds. Advanced concepts have been proposed to overcome these problems and take advantage of higher velocities to make boiler designs more compact. The present concepts are based on experimental superficial velocities up to 15 fps.

Particle Size: The particle size is based primarily on the gas velocity. Limestone/dolomite utilization and particle carry-over are also considered for each design.

Excess Air: Excess air for the primary beds and carbon burn-up cell is ~10% and $\geq$ 30% respectively. These levels are selected to achieve combustion efficiencies of approximately 90% in the primary bed and $\geq$ 90% in the carbon burn-up cell.

Bed Depth: Bed depth for atmospheric-pressure operation is limited by fan technology. The maximum design pressure drop which can be used with a forced draft fan is ~100 inches H_2O for air flows near 100,000 cfm. The gas-side pressure drop, excluding the fluidized bed and gas distributor, is 10 to 15 inches H_2O. This permits an expanded bed depth up to 5 feet with an allowance for the distributor of 30% of the bed pressure drop. However, the power requirement to overcome 100 inches water back pressure is excessive (~3000 HP for 75000 cfm). The design bed depth depends on an assessment of fan cost, power requirements, and boiler performance and cost as a function of bed depth. Expanded bed depth for pressurized operation is set at approximately 15 feet. Deep beds can be used with the pressurized system with very little penalty from the increased pressure drop. Deep beds minimize problems of coal feeding, sorbent recirculation, and steam piping. Beds deeper than 15 feet are not considered for the present design concept in order to avoid large height to diameter ratios, potential fuel and temperature distribution problems, and incorporation of multiple boiler functions in the same bed. Advanced concepts have been proposed to overcome these problems and achieve a more economical system.

Ca/S Ratio: A calcium to sulfur molar ratio of 6 is used for the boiler designs burning a 4% sulfur coal. This includes fresh make-up stone plus the calcium oxide from regenerated stone. Data are not available at all the projected operating conditions. Available data were reviewed and a Ca/S molar ratio projected which accounts for differences between the experimental conditions and the proposed design conditions. These differences include the type of operation -- regeneration vs once-through; operating conditions -- e.g., bed temperature, bed depth, gas velocity; and scale of operation. Lower sulfur fuels, more reactive stones, and operating conditions selected for optimum sulfur removal will reduce the stone requirement of six times the stoichiometric ratio. Operating conditions for optimum sulfur removal may increase boiler cost but reduce the solids disposal problem.

Design Specifications

Design specifications for the boiler systems were based on available data and technical assessment under the proposed operating conditions. The specifications are summarized on the next page.

The design philosophy for all the boiler designs is to maximize shop fabrication and standardization of boiler components in order to minimize cost. The industrial boiler design is such that primary modules can be shipped by rail -- dimensions within 13 ft x 16 ft x 40 ft. Selection of boiler tube materials is based on conventional practice. Preliminary evaluation of boiler tube material test data in fluidized bed combustors indicates that conventional tube materials can be used. Preliminary test data on a pilot unit with a test cascade and vendor data on particulate collection indicate that gas turbine blade erosion and corrosion will not be a serious problem in the pressurized utility plant. A fluid bed to boiler tube heat transfer coefficient of 50 $\text{Btu/hr-ft}^2\text{-°F}$ is assumed for the boiler designs on the basis of data from six experimental fluidized bed combustors. The heat transfer coefficient for tubes above the bed, but still in the splash range of bed material, is assumed to be 30 $\text{Btu/hr-ft}^2\text{-°F}$. More data are required for accurate design of heat transfer surfaces above the bed and in the freeboard. Particle carry-over data are not available for combustion of coal in limestone or dolomite beds operating at velocities of 10 to 15 fps with continuous recycle of the stone. A design basis was selected using the

DESIGN SPECIFICATIONS
FOR FLUIDIZED BED COMBUSTION BOILERS

CONSTRUCTION	Maximum shop fabrication and standardization
BOILER TUBE MATERIALS	Conventional tube materials
GAS TURBINE (PRESSURIZED UTILITY PLANT)	Conventional blade design and materials
HEAT TRANSFER COEFFICIENT, Btu/hr-ft^2-°F	
Tubes in Bed	50
Tubes above Bed in Splash Zone	30-40
PARTICLE CARRY-OVER, grains/SCF	7-15
COMBUSTIBLE LOSS, %	
Pressurized Boiler	1-1.5
Atmospheric pressure Boilers	1-2
COAL FEED DISTRIBUTION	1 feed point per 10 ft^2

available carry-over data on fluidized bed combustion systems and an assessment of solid feed size distributions, attrition, and rate of entrainment for the proposed operating conditions. Dust loadings of 7 to 15 grains/SCF are projected. Combustible losses of 1 to 2% are projected from the experimental data. The coal feed system design is based on data obtained in a 5-foot diameter bed study. Results indicate that coal feed points should be located one for each 10 square feet of bed area.

INDUSTRIAL BOILER APPLICATION

The application of fluidized bed combustion to industrial steam generation was studied in the light of the functional, operating, and design specifications and design concepts outlined. Initial boiler plant concepts concentrated on systems which incorporated sorbent regeneration processes(10). However, the problems of providing and operating industrial sorbent regeneration and sulfur recovery processes for industrial users appear to make this concept impractical for a small industrial application. Regeneration may be practical if a large on-site or off-site regeneration-sulfur recovery facility is available. Two fluidized bed boiler plant concepts were developed which incorporate once-through limestone systems. Preliminary boiler plant designs were prepared for these two systems on the basis of the specifications and material and energy balances for the systems. Operating procedures were developed and boiler plant performance projected. Capital and operating costs are based on industrial boiler practice and the estimates compared with conventional industrial boiler systems.

Design

An industrial fluidized bed boiler plant preliminary design was prepared which includes all equipment between the following terminals: inlets to the economizer, coal feeder, limestone feeder, and stack; outlets from the ash silo and superheater. The design is based on the specifications presented on pages 45-52. The components of the system are illustrated in Figure 12 and include:

- Steam generator
- Economizer
- Coal and limestone feed systems
- Pollution control
- Waste solids handling system
- Instrumentation and controls.

Steam Generator

The atmospheric pressure fluidized bed industrial steam generator design concept is shown in Figure 13 . The steam generator comprises two separate shipping modules:

- The primary module is the main combustion unit and consists of four fluidized beds containing 1-inch diameter horizontal tubes in the bed with a 6-inch horizontal, 3-inch vertical diamond spacing. The beds are not separated by water walls. Horizontal particle baffle screens using 1-inch tubes on 3-inch centers are located above the beds. A recirculation pump provides the forced circulation of water through the tubes. Tube-free volumes are located between the submerged surface and grid (12 inches) and the submerged surface and baffle screen (8 inches). Freeboard above the beds is open to provide easy access to the boiler. The four beds are within a waterwall shell but are not divided by water walls. Air is fed to each bed from a divided plenum. A bubble cap air distributor is used with coal feed points every 10 square feet. The primary module is 10 ft x 14 ft x 40 ft.
- The secondary module contains a carbon burn-up cell, superheater section, and convection pass. High carbon content solids (up to ~50% carbon), which are carried over from the primary module, are fed to the carbon burn-up cell. The solids are removed from the gas leaving the primary module by cyclones. The solids are pneumatically transported to the carbon burn-up cell bed, and the gases pass over the bed, combining with flue gas from the bed. The car-

Dwg. 2965A04

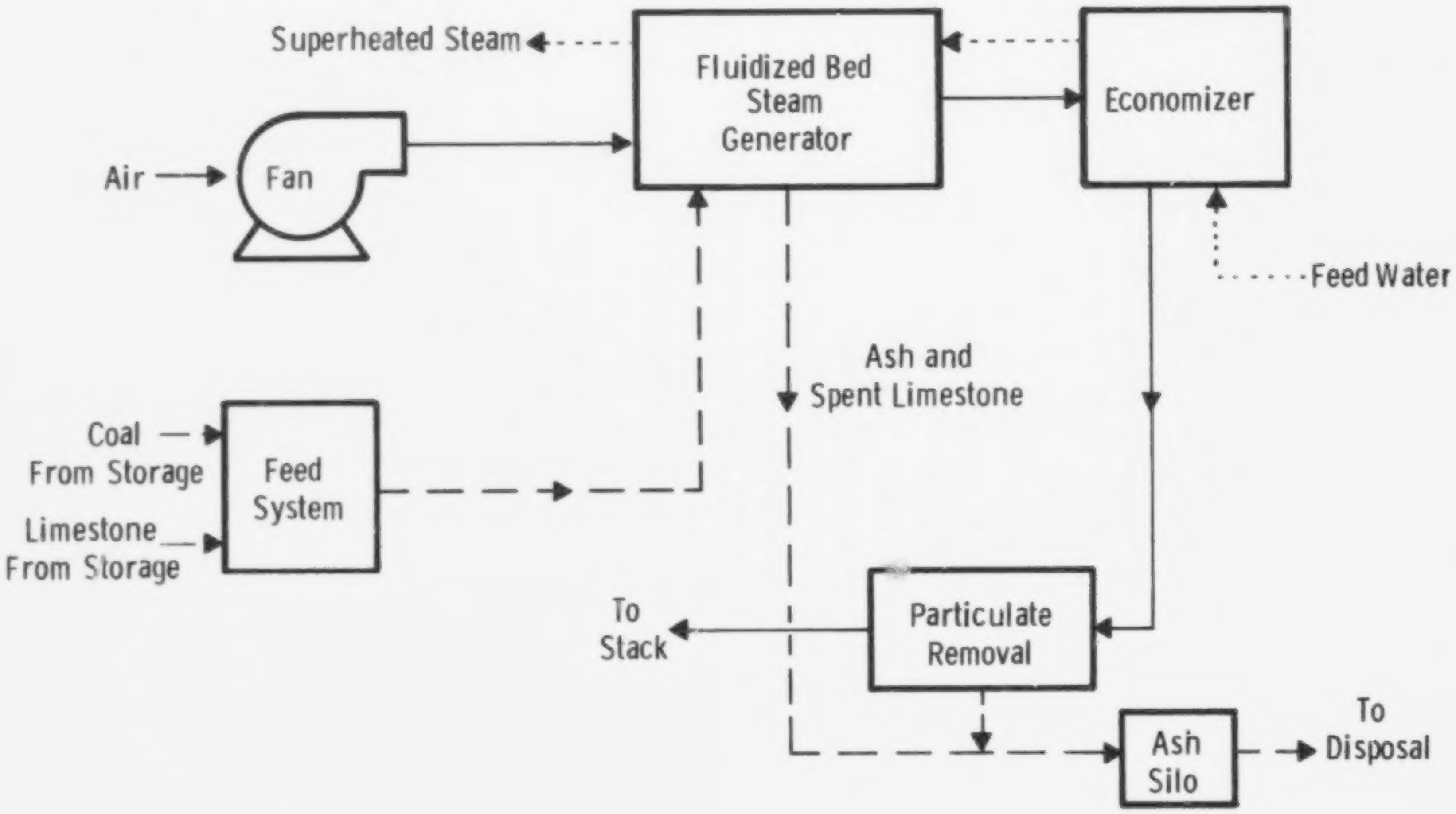


Fig. 12 —Industrial fluidized bed boiler system

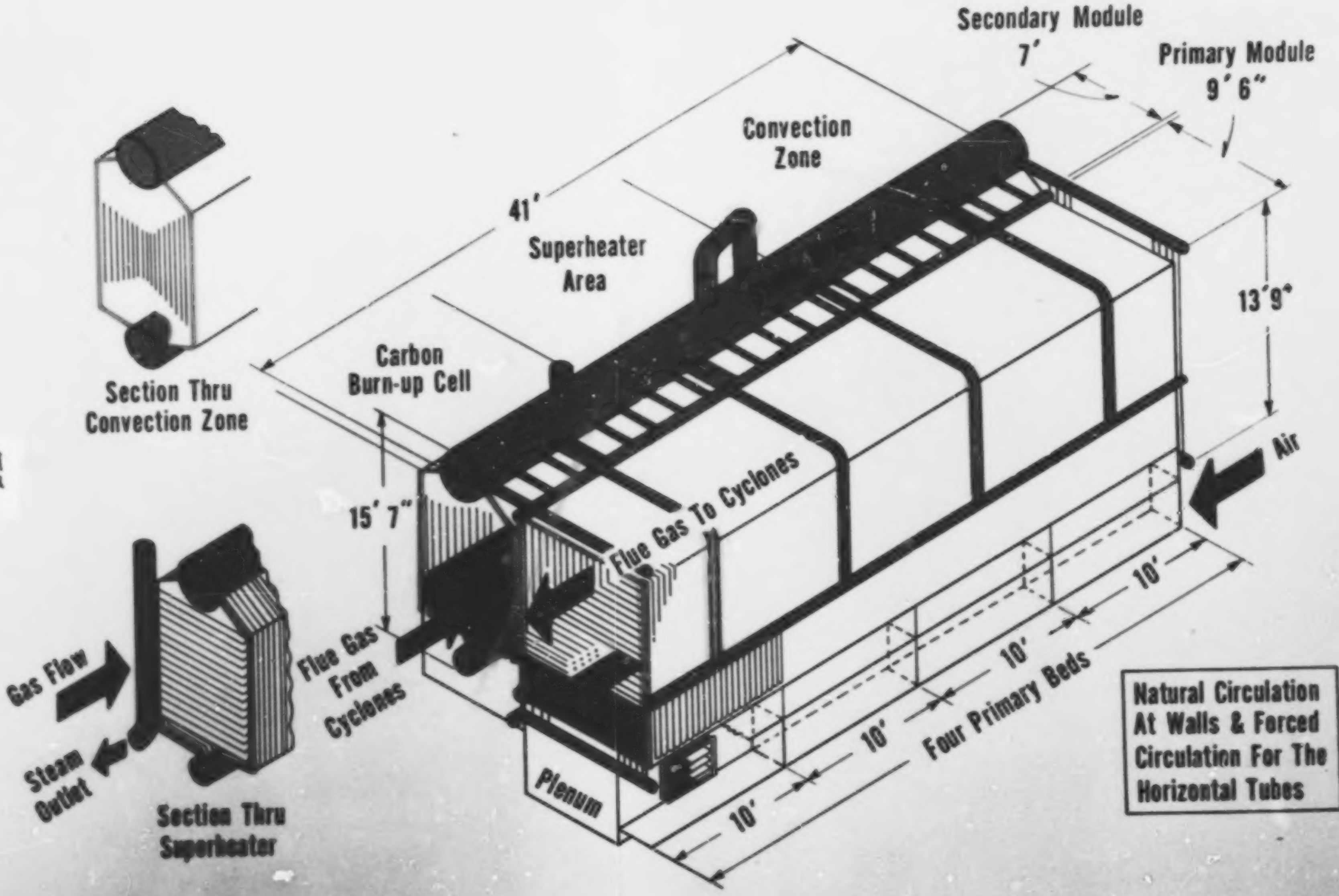


Fig. 13-Industrial Fluidized Bed Boiler Design

bon burn-up cell is sectioned into four water-walled beds to provide for boiler turn-down. These beds are operated parallel to the fuel burning beds in the primary module. Flue gas from the carbon burn-up cell and primary cyclones pass through the superheater section, which is a conventional design. The superheat represents ∿ 15% of the heat output in the steam. Heat from the flue gas is then recovered in a convection pass to a level where only one heat trap (economizer) is needed. The secondary module is 8 ft x 15 ft x 40 ft.

The steam generator design and operating characteristics are summarized in the next matrix.

Economizer

An extended surface economizer (or feed water heater) is used to recover sensible heat in the gas leaving the convection pass. This selection is based on a study of heat trap costs which included tubular and regenerative air heaters and bare and extended surface economizers.

Coal and Limestone Feed Systems

Coal and limestone are received from storage, crushed to -1/4 inch, mixed, and fed to 32 solids feed points in the primary module. Commercial equipment is available to feed coarse coal against the 50 to 70 inches water design pressure and to monitor the feed rate. The problem is to achieve a uniform feed rate to a large number of feed points. A schematic of the coal feed system selected is shown in Figure 14.

The crushed coal is transferred to a feeding hopper and then to a moving belt gravimetric feeder with adjustable belt speed for different feed rate control. Limestone flow is controlled prior to mixing with the coal on the gravimetric feeder. The coal and limestone from the gravimetric feeder drop into a four-way splitter to divide the coal into four equal streams, one for each bed, with an individual shutoff valve for each stream. However, no individual control of coal feed

Preceding page blank

FLUIDIZED BED BOILER DESIGN AND OPERATING CHARACTERISTICS

Industrial

CAPACITY	
Steam, lb/hr	250,000
Conditions	600 psig, 750°F
DESIGN FEATURES	
Water Circulation	Forced & natural circulation
MODULES	
Number/unit	2
Beds/unit (inc. CBC)	5
Bed Orientation	Horizontal, in-line
HEAT TRANSFER SURFACE ARRANGEMENT	Horizontal
Tube Size, in.	1
BED DEPTH, ft	2.5
GAS VELOCITY, fps	10-12.5
BED TEMPERATURE, °F	
Design Point	1650
Part Load	≥ 1300
CBC	1900-2000
PARTICLE SIZE, in.	- 1/4
EXCESS AIR, %	
Primary Beds	10
CBC	50
Total	23.6
CONTROL METHOD	Bed temperature and bed shut-off
SULFUR REMOVAL STONE	Limestone
Scheme and Ca/S Ratio	1. wet scrubbing, 1.2 2. once-through, ≤ 6

Dwg. 2963A25

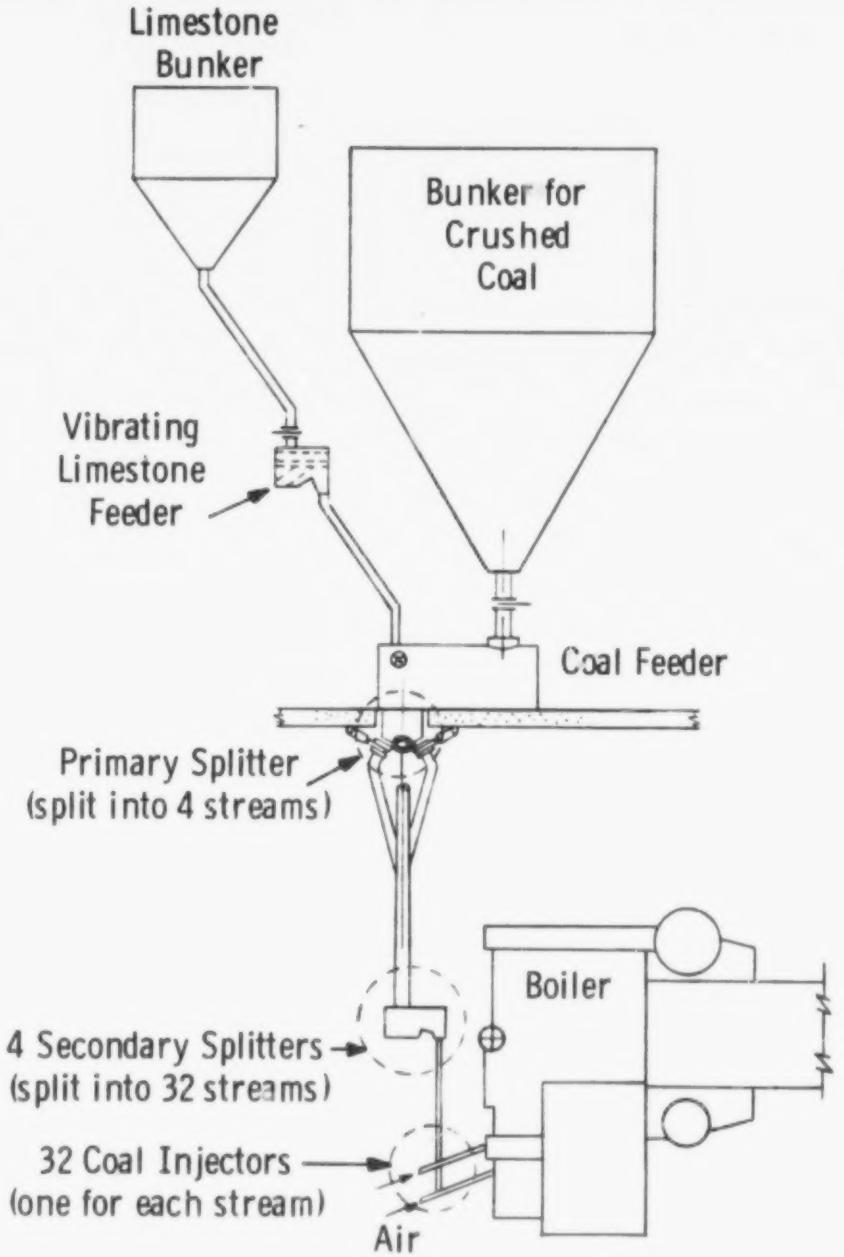

Limestone Bunker
Bunker for Crushed Coal
Vibrating Limestone Feeder
Coal Feeder
Primary Splitter (split into 4 streams)
Boiler
4 Secondary Splitters (split into 32 streams)
32 Coal Injectors (one for each stream)
Air

Fig. 14 —Coal feed system

rate for each stream is possible. Each stream of coal is again equally split into eight separate portions, one for every coal feed point, by using a vibrating table. The coal is then fed pneumatically into the bed.

Coal drying is also accomplished in the coal feeding system by using preheated sealing air. No condensation of moisture in the coal feeding lines is expected. The tight enclosure in the feeding system will prevent venting of sulfur dioxide or particulates into the atmosphere during this drying operation.

Each individual coal feeder is a "straight-in", replaceable, design forming a 30° angle with the distributor plate to facilitate the maintenance and replacement of a coal feeder even during partial boiler operation.

Pollution Control Systems

Two sulfur dioxide-particulate control systems were developed. Both systems use the same steam generator design, but incorporate different sulfur dioxide and particulate control concepts. Flow schematics of the two concepts -- once-through dry limestone and wet scrubbing -- are shown in Figures 15 and 16.

The once-through dry limestone system has fresh limestone fed to the fluidized bed boiler. The sulfur dioxide is removed in the boiler and the spent stone withdrawn for dry disposal. The system is designed to handle limestone at six times the stoichiometric calcium to sulfur feed ratio. This is to provide SO_2 removal with a 4% S coal. Final particulate removal is achieved by an electrostatic precipitator designed for 99.5% efficiency.

The wet scrubbing system provides an alternative sulfur dioxide control scheme which avoids the use of large quantities of limestone. The limestone is fed to the fluidized bed boiler, where the stone is calcined. Some sulfur removal occurs in the bed. The calcined stone, CaO, is mixed with water to form a slurry and pumped to a wet scrubber. The wet scrubber is designed to remove the SO_2 and particulates from

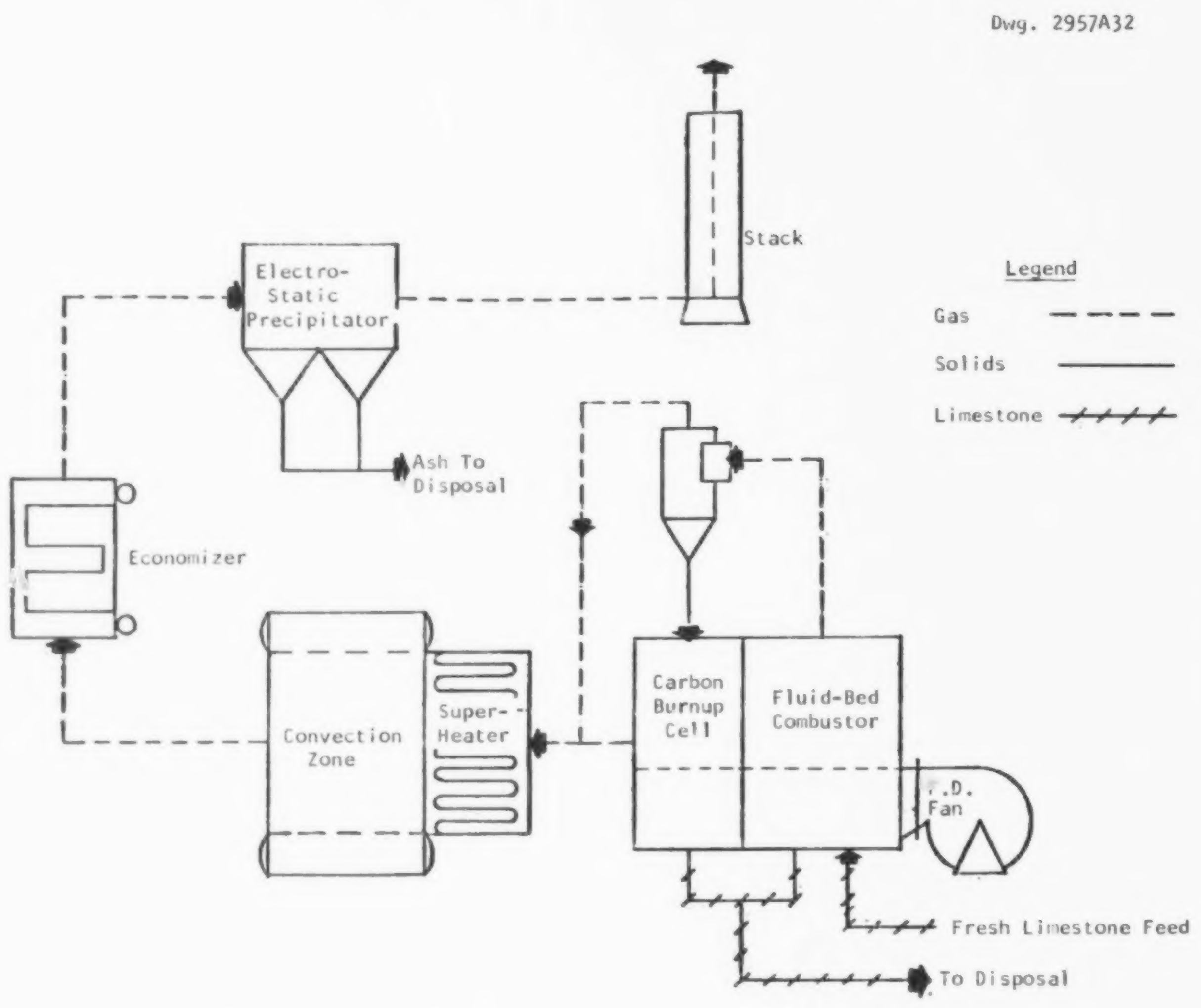


Fig. 15 - System Schematic - Once Through Scheme

Dwg. 2957A31

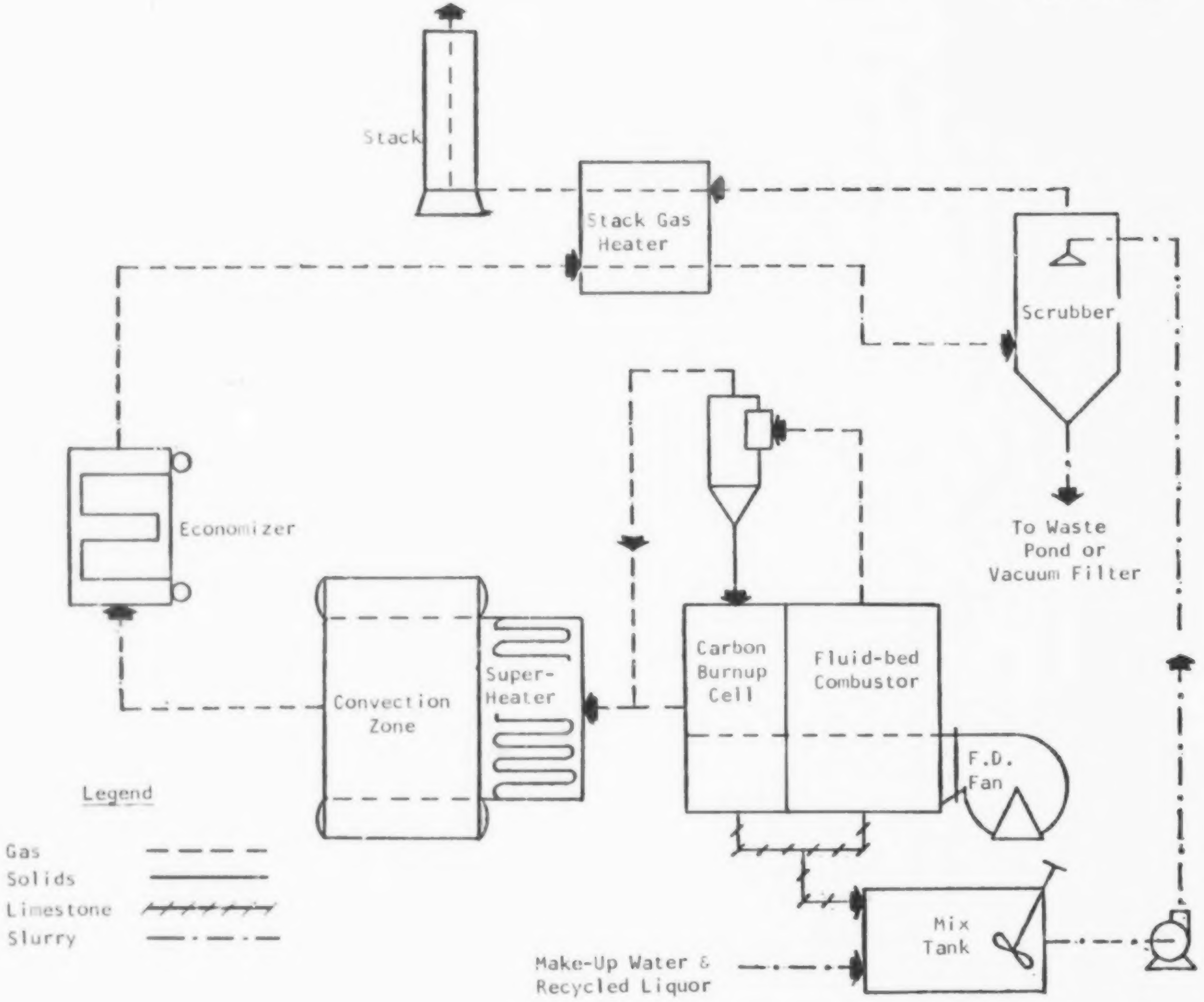


Fig. 16 - System Schematic - Wet Scrubbing Scheme

the gas. A stack gas reheater may be required, depending on the temperature, emission levels, and necessity of avoiding a water vapor plume. The limestone requirement for the wet scrubbing system is projected to be only 1.2 times the stoichiometric calcium to sulfur ratio to achieve the same SO_2 control.

Water Solids Handling System

There are two solids handling systems in the dry solids system: one for transporting carbon-rich solids from the primary cyclones to the carbon burn-up cell, and the other for transporting solids from the fluidized beds from underneath the superheater and from the electrostatic precipitator to disposal. A pneumatic transport system is used in all cases. The wet scrubbing system has to provide for the disposal of a filter cake containing about 50% water.

Controls and Instrumentation

The overall boiler control is divided into three subdivisions -- the combustion control, the feedwater flow control, and the steam temperature control. The basic control principles for the fluidized bed boiler are similar to those for any subcritical recirculating boiler.

Combustion Control System

Steam drum pressure is the load-sensitive control element and is used to initiate the fuel feed. Combustion air is fed to a common plenum by the forced draft fan with the plenum air pressure kept constant by the inlet vanes which are positioned by the signal from the fuel/air ratio setter. Individual dampers control the combustion air flow to each individual primary bed and each individual section of the carbon burn-up cell.

Feedwater Flow Control System

Feedwater and steam flow signals are compared. If a difference occurs, a signal is sent to the feedwater flow control. The steam drum level is compared to a set point. If a difference exists, a signal is sent to the feedwater control system.

Steam Temperature Control System

The outlet steam temperature signal is compared to a set point. The resulting error signal is combined with the steam flow signal. The combined signal is passed through a steam temperature attemperator hand-auto station to a spray flow control valve.

Operation

Start-Up

The boiler is started up first by firing an auxiliary gas burner above the bed to raise boiler pressure to on-line conditions (i.e., 600 psig and 489°F). Then the bed material is heated up to minimum coal injection temperature (~ 800°F) by injection of auxiliary gas fuel into the minimally fluidized bed. Only the first of the four beds and the first of the four sections in the carbon burn-up cell (CBC) are started this way. The start-up of the other beds and the other sections can rely on solid recirculation from the adjacent operating bed to raise the bed temperature. Once the bed reaches the minimum coal injection temperature, the coal feed is started, and the load is increased.

Load Control

Load control in the industrial boiler is achieved by adjustment of the bed temperature and turning on and off the fluidized beds. Change of bed temperature alone can provide up to 30% or 50% load reduction in a single bed, depending on whether the once-through dry solid or wet scrubbing system is employed. Turning beds off can provide a turn-down ratio of at least 4:1 for the entire boiler.

The bed temperature in the CBC is kept constant during turn-down for efficient carbon burn-up. The proposed design divides the CBC into four separate sections, each corresponding to a primary bed.

Turn-down by shutting down a bed would require shutting down the corresponding section in the CBC. The bed temperature in the CBC is kept constant during turn-down by decreasing the excess air.

Normal Shut-Down

When removing one bed from service, the coal feed is shut off first while fluidizing air is maintained to burn the residual coal in the bed and to prevent the deposit of coal in the pneumatic transport lines. After the residual coal is burned out, the bed temperature starts to drop, and the fluidizing air can be shut off. However, the recirculation water flow through the immersed horizontal tubes will be maintained throughout the operation.

For shutting down the entire boiler, one fuel-burning bed section is shut down at a time. The cooling rate is limited to avoid undue thermal stresses. A cooling rate of 100°F per hour, the same as the heating rate, is recommended. The recirculating pump is kept running until the steam generator is cooled to below 200°F and is ready for draining.

Emergency Shut-Down

Emergency situations such as loss of combustion air flow, loss of recirculation pump, loss of fuel feed, loss of steam drum water level, sudden burn-out of bed tubes, and loss of bed fluidization, and their remedial procedures are discussed in Volume II.

Performance Characteristics

Overall Boiler Efficiency

The comparison of total boiler efficiency between once-through dry solid and wet scrubbing systems is presented in Table 11 . The wet scrubbing system has higher boiler efficiency because the stack gas temperature in the present design is 132°F, compared to 350°F in the dry

TABLE 11

COMPARISON OF BOILER PERFORMANCE BETWEEN ONCE-THROUGH DRY SOLID AND WET SCRUBBING SYSTEMS

	Dry Solid (%)	Wet Scrubbing (%)
Loss due to calcination and SO_2 absorption	2.74	0.56
Loss due to water and hydrogen in fuel	3.80	3.83
Loss due to unburned carbon	1.93	2.05
Loss due to radiation and unaccounted for	1.50	1.50
Loss due to evaporation in wet scrubber	--	4.84
Loss due to flue gas sensible heat	6.61 (350°F Flue Gas)	1.30 (132°F Flue Gas)
Total Loss	16.58	14.08
Overall Boiler Efficiency	83.42	85.92

solid system. An additional efficiency loss of about 5% in the wet scrubbing system is expected if the flue gas is to be heated up from 132°F to 350°F.

Draft Losses

A summary of draft losses for both the once-through dry solid system and the wet scrubbing system is presented in Table 12 and a comparison of corresponding power requirements for both systems is estimated in Table 13 .

Air Pollution Abatement Capability

The projected control capability of the industrial fluidized bed boiler for NO_x, SO_2, and particulate is summarized in Table 14. NO_x emissions from the industrial boiler are expected to be in the range of 250 ppm (0.40 lb $NO_2/10^6$ Btu) to 500 ppm (0.81 lb $NO_2/10^6$ Btu), compared to ∿550 ppm from a conventional spreader stoker. SO_2 removal depends primarily on the amount of limestone fed and is expected to be >90% for the once-through dry solids system. For a wet scrubbing system, the SO_2 removal efficiency is expected to be ∿85%. For a coal containing 4.3 wt % sulfur, the SO_2 emission is in the range of 350 to 500 ppm (0.80-1.13 lb/10^6 Btu). For the once-through dry solids system, the particulate loading in flue gas is expected to be less than 0.02 gr/SCF. The particulate removal efficiency of the present wet scrubber design is ∿98%.

Boiler Plant Costs

The capital costs for the two industrial boiler plant designs are summarized in Table 15 . The costs were prepared by Erie City Energy using their standard boiler pricing procedures and vendor quotes on auxiliary equipment. Operating costs are summarized in Table 16 .

TABLE 12

DRAFT LOSSES

	Dry Solids System Inches W.G.	Wet Scrubber System Inches W.G.
Fluidized Bed & Forced Draft Ducts	26.7	26.7
Mechanical Collector	5.0	5.0
Convection Pass, Economizer, and Flues	10.9	10.9
Precipitator	0.7	--
Scrubber	--	16.2
TOTAL	43.3	58.8

TABLE 13

COMPARISON OF POWER REQUIREMENTS(a)

	Dry Solids System	Wet Scrubber System
Forced Draft Fan, HP	700	950
Recirculating Pump, HP	200	200
Coal Crusher, HP	60	60
Slurry Pumps, HP	--	150
Total Power Requirements, HP	960	1360
Power Requirements % of Output(b)	0.86	1.21

(a) Only major operating horsepower requirements are shown.

(b) Where a horsepower hour is 2544 Btu and output is 289 million Btu per hour.

TABLE 14

AIR POLLUTION CONTROL CAPABILITY OF INDUSTRIAL FLUIDIZED BED BOILER

	Dry Solid System	Wet Scrubbing System
NO_x Emission		
ppm	250-500	250-500
$lb/10^6$ Btu (as NO_2)	0.40-0.81	0.40-0.81
SO_2 Emission		
ppm	350 (90% removal)	350-500
$lb/10^6$ Btu	0.80	0.80-1.13
Particulate Emission		
gr/SCF	0.01-0.05	0.01-0.05
$lb/10^6$ Btu	0.02-0.08	0.02-0.08

TABLE 15

CAPITAL COSTS FOR INDUSTRIAL FLUIDIZED BED STEAM GENERATION

	Once-Through Dry Solids System		Once-Through Wet Scrubber System	
	Total Installed Cost $	% of Total Cost	Total Installed Cost $	% of Total Cost
Crusher	18,000	1.18	18,000	0.96
Fuel System (Not including bunkers and system upstream of bunkers)	99,000	6.50	99,000	5.35
Forced Draft Fan	40,000	2.62	59,000	3.19
Fuel System Sealing Fan & Heater System	22,000	1.44	22,000	1.19
Steam Generator System, Recirculating Pump and Economizer	848,000	55.64	848,000	45.79
Ash Handling System	255,000	16.73	150,000	8.10
Mechanical Dust Collector	45,000	2.95	45,000	2.43
Wet Scrubber System	--	--	400,000	21.60
Dewatering	--	--	120,000	6.48
Electro-Static Precipitator	106,000	6.96	--	--
Controls	91,000	5.98	91,000	4.91
TOTAL	1,524,000		1,852,000	
SPECIFIC COST $/lb steam/hr	6.10		7.40	

TABLE 16

OPERATING COSTS FOR INDUSTRIAL FLUIDIZED BED STEAM GENERATION

	Once-Through Dry Solids System ¢/10^6 Btu	Once-Through Wet Scrubbing System ¢/10^6 Btu
Capital Charges(a)	12.70	15.40
Fuel Cost	30.00	30.00
Labor	9.00	9.00
Limestone(b)	9.70	2.10
Power	1.10	1.50
Solids/Slurry Disposal(c)	13.50	13.50
TOTAL	76.00	71.50

(a) Capital charges at 16.7% per year, 70% load factor.

(b) $8/ton.

(c) $5/ton.

Evaluation

Industrial fluidized bed combustion boilers were evaluated by assessing their effectiveness for economy of steam generation, effectiveness for pollution abatement, market projection and the status of technology. Capital and operating costs were projected for alternative fluidized bed combustion systems based on the two preliminary designs. The costs for three alternative coal-fired fluidized bed combustion systems and for gas-and oil-fired fluidized bed combustion systems are projected in addition to the once-through wet scrubbing and dry limestone systems. Costs for the two coal-fired systems are projected to include regeneration of the limestone, and costs are projected for using low-sulfur coal or char in the fluidized bed boiler. The cost estimates for the coal-fired fluidized bed boiler were used to project the costs for gas- and oil-fired fluidized bed combustion boilers. The costs of these systems are compared with the cost of conventional coal-and oil-fired industrial boiler alternatives in Tables 17 and 18. All of the systems burning high-sulfur fuel are based on similar air pollution abatement: 70 to 90% removal of SO_2, 0.02-0.1 lb particulates/10^6 Btu, 0.4-1.0 lb $NO_2/10^6$ Btu. The steam costs presented in Table 18 are very dependent on fuel, limestone, and waste disposal costs. These costs for each system will depend on plant location, fuel policies, environmental regulations, fuel sulfur content, limestone activity, and politics. The steam costs presented serve to illustrate the various component costs.

The cost estimates show:

- Capital cost of a once-through dry limestone fluidized bed boiler is 20% less than a conventional spreader stoker with wet scrubbing or the fluidized bed limestone scrubbing scheme.
- The fluidized bed limestone scrubbing scheme and once-through dry solid scheme are comparable to each other in total steam cost and competitive with a spreader stoker with wet scrubbing, with costs varying less than 10%.

- Limestone regeneration schemes have an approximately 15% cost advantage over the other systems, if a large sulfur recovery facility is available on-site or off-site.

- A spreader stoker burning low-sulfur coal is more expensive than one burning high-sulfur coal with wet scrubbing for SO_2 removal because of the high cost of low-sulfur coal.

- Although the capital cost of the field-erected oil- or gas-fired boiler is substantially less than other systems, the total cost is competitive with other systems, again, because of the high fuel cost currently quoted for the Northeastern United States.

- The capital cost of oil- and gas-fired boilers is 55 to 70% less than coal-fired boilers.

- Gas- or oil-fired fluidized bed boilers are not economical. The gas-or oil-fired fluidized bed boiler modules, excluding the fuel feed system and carbon burn-up cell, are basically unchanged from a coal-fired unit. Thus, significant cost reductions in going from coal to gas or oil, which are realized in conventional boilers, are not projected for fluidized bed boilers.

- A fluidized bed boiler burning the desulfurized char is the most economical case, if the desulfurized char is available at a cost per Btu equal to that of high-sulfur coal. Conventional boilers cannot effectively burn char.

TABLE 17

CAPITAL COST OF COAL- AND GAS/OIL-FIRED INDUSTRIAL BOILER
POLLUTION CONTROL ALTERNATIVES ($/lb/hr)

	FLUIDIZED BED COMBUSTION BOILER (Shop Fabricated)	CONVENTIONAL BOILER (Field-Erected)
COAL-FIRED[a]		
Desulfurized Char	5.25	---
Low-sulfur Coal	5.25	5.50
Limestone Scrubbing	7.40[b]	7.60
Once-through Dry Limestone	6.10	---
Limestone Regeneration		
On-site facility	7.75	---
Off-site central facility	6.10	---
GAS/OIL-FIRED		
Clean Fuel	4.00-5.00	2.44[c]
High-sulfur Oil		
Once-through limestone	5.25-5.50[d]	3.10[e]
Wet scrubbing	7.00-7.50[f]	4.50

(a) Costs do not include cost of equipment before coal feeding system, e.g., railhead, bunkers. This cost is $.25-1.00/lb/hr.

(b) Cost is identical for two processes: calcine stone in boiler and then once-through a wet scrubber; or remove SO_2 in bed, externally regenerate stone, and scrub effluent.

(c) Cost for a packaged system would be $2.00/lb/hr.

(d) Either once-through limestone or off-site regeneration.

(e) The percentage sulfur removal in this case will be low.

(f) Limestone calcining in the bed followed by wet scrubbing.

TABLE 18

INDUSTRIAL FLUIDIZED BED BOILER COST SUMMARY

¢/10^6 Btu

	CAPITAL CHARGES[(a)]	FUEL COST	LABOR	SORBENT[(b)]	POWER	SOLIDS/SLURRY DISPOSAL[(c)]	TOTAL
COAL-FIRED							
Fluidized Bed Combustion							
Desulfurized Char	10.95	(30)	9	---	1.1	1.90	52.96
Limestone Scrubbing	15.40	30	9	2.08	1.5	13.50	71.5
Once-through Dry Limestone	12.70	30	9	9.69	1.1	13.50	76.0
Limestone Regeneration							
On-site	16.20	30	9	1.15	1.5	5.80	63.67
Off-site	12.70	30	9	3.45	1.5	1.90	58.57
Spreader Stoker							
Low-Sulfur Coal	11.50	60	9	---	1.1	1.90	83.51
High-Sulfur Coal -- Wet Scrubbing	15.90	30	9	2.08	1.5	13.50	72.00
GAS/OIL FIRED							
Conventional Field Erected							
Clean Fuel	5.10	65	4	---	0.4	---	74.50

(a) Capital charge 16.7% per year, 70% load factor; fuel cost $7.50/ton ≈ 30¢/$10^6$ Btu.

(b) Raw stone $3.00/ton; regenerated stone $9.00/ton.

(c) $5/ton disposal cost (cost information has varied from $0-10/ton).

The steam cost is highly dependent on fuel cost. Thus the relative advantage of the alternative systems will depend on cost and availability of fuels. The present market indicates that industrial boilers will probably burn clean fuels. Gas- and low-sulfur oil-fired boilers provide low capital cost, high reliability, and low SO_2, NO_x, and particulate emissions.

Significant cost reductions do not appear attainable for industrial fluidized bed boiler designs. The need for NO_x control may even result in an increase in cost. The potential for the application of fluidized bed boilers for industrial steam generation is not attractive at this time unless:

- Low-cost, low-sulfur char is available
- Clean fuels are not available and the removal of sulfur from the fuel prior to combustion and/or removal of sulfur as sulfur oxides from the flue gas proves uneconomical.

ELECTRIC UTILITY APPLICATION

Preliminary designs of two utility boilers were developed: one carries out combustion at one atmosphere; the other, at ten atmospheres. The designs are based on the specifications outlined on pages 45-52, material and energy balances for the respective power systems, and an evaluation of the alternative concepts.

The steam system used as a basis for the boiler designs is that from the Hammond No. 4 unit of Georgia Power and Light:

Boiler Pressure, psia	2400
Superheat Temperature, °F	1000
Reheat Temperature, °F	1000
Condenser Pressure, in. Hg	3
Feedwater Heater Stages	6

The heat rate of this plant as a function of its power output is shown in Figure 17 ; at full load the overall efficiency of Hammond No. 4 is 37%.

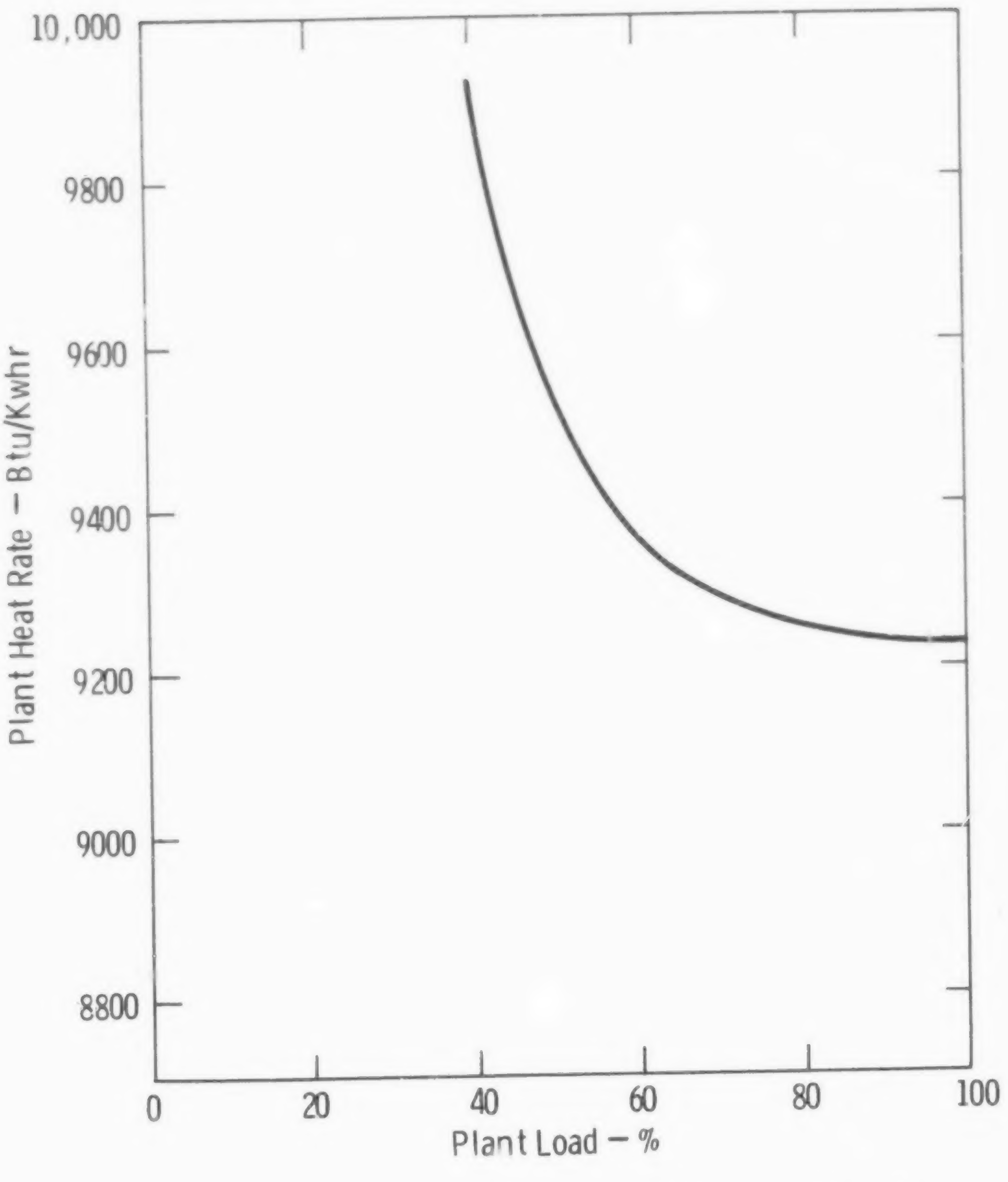


Fig. 17 – Part load performance of Hammond #4 unit 2400/1000/1000/3 In.

Pressurized Fluid Bed Boiler Power Plant Design

System Concept

The pressurized fluid bed boiler power plant design is based on an evaluation of boiler concepts (11-15), experimental data(13), and power cycles(11).

The system concept for the high-pressure fluidized bed boiler in a combined cycle plant is shown schematically in Figure 18 . Combustion air is supplied by the gas turbine compressor. Coal is crushed and dried prior to feeding into the bed. The bed material is a sorbent which removes the sulfur from the products of combustion as the coal is burned. The bed is maintained at a temperature below the agglomeration point by heat transfer to the steam cycle. The spent dolomite is regenerated and recycled. The sulfur released in the sorbent regeneration process is converted to sulfur in a subsequent sulfur recovery process. Make-up dolomite is fed in with the coal.

All of the ash from the coal is elutriated from the bed along with a significant amount of unburned carbon and attrited sorbent. A high percentage of the particulates from the primary bed are collected in the primary separation and fed to a fluidized bed carbon burn-up cell which operates at a higher temperature and with greater percent excess than the primary bed. The effluents from the primary bed and the carbon burn-up cell are blended and passed through a secondary particulate removal device to reduce the solids content to the level required to attain a low erosion rate in the gas turbine. After expansion through the gas turbine, the exhaust gases are cooled by two stages of stack gas coolers. A third-stage particulate removal device may be necessary to meet stack emission standards. The steam cycle has one stage of reheat and regenerative feed water heating which is partially in parallel with the stack gas cooler.

Power Cycle Conditions

Nominal plant capacities of 300 MW and 600 MW are considered. The design point conditions are summarized in Table 19.

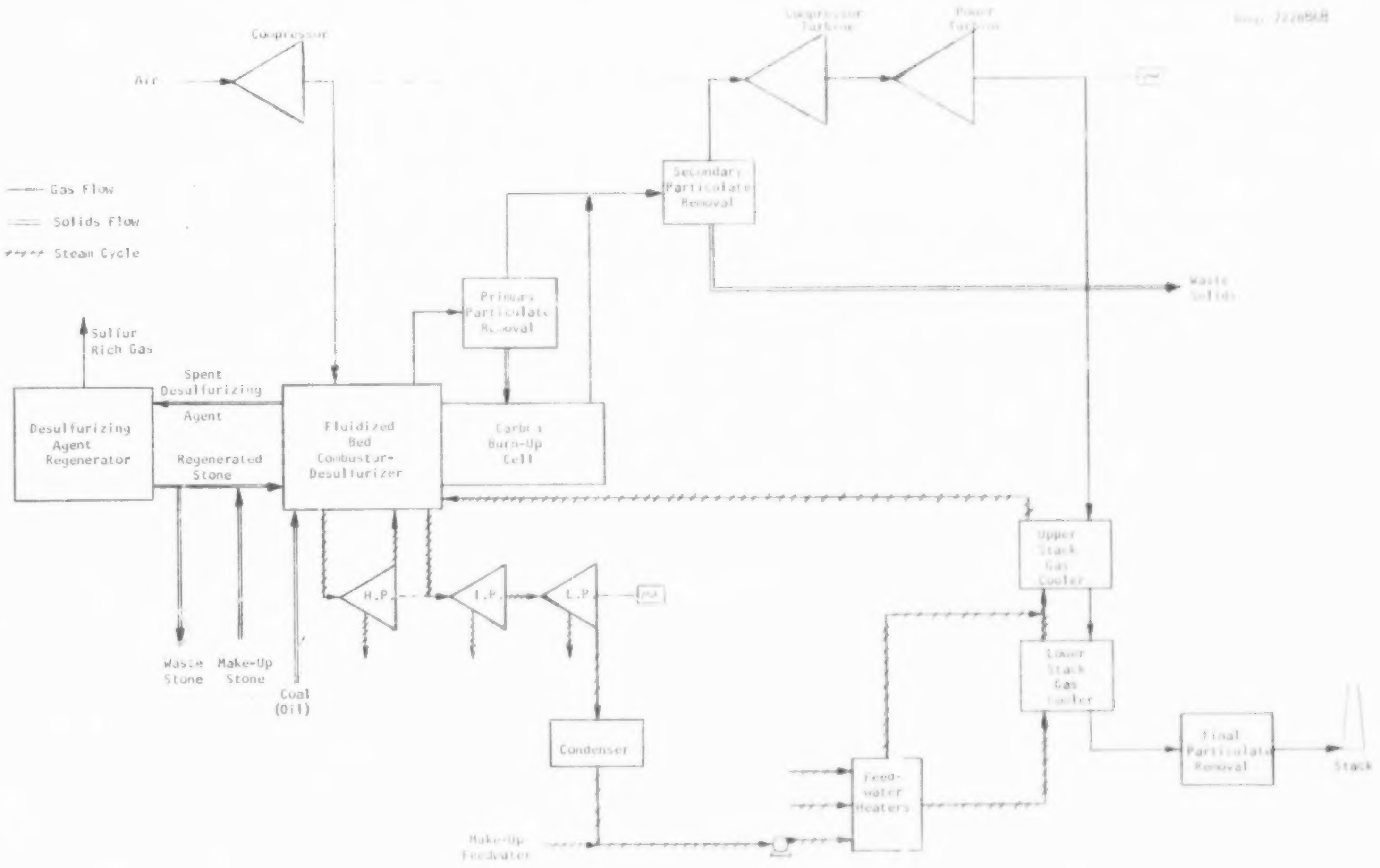


Fig. 18 – Pressurized fluid bed boiler power system

TABLE 19

POWER CYCLE CONDITIONS

	Capacity - MW	
	318	635
Boiler Pressure, psia	2,400	2,400
Initial Steam Flow, lb/hr	1,727,020	3,454,040
Steam Temperature, °F		
Initial	1,000	1,000
Reheat	1,000	1,000
Condenser Pressure, in. Hg	3	3
Final Feedwater Temperature, °F	578	578
Compressor Air Flow, lb/sec	650	1,300
Gas Turbine Temperature, °F	1,600	1,600
Gas Turbine Pressure Ratio	10:1	10:1
Turbine Cooling Air	5%	5%
Gas Turbine Pressure Drop	3%	3%
Excess Air	10%	10%
Stack Temperature, °F	275	275
Gas Turbine Power, kW	56,557	113,113
Steam Turbine Power, kW	270,029	538,400
Net Plant Power, kW	318,485	635,362
Plant Heat Rate, Btu/kWh	8,953	8.974

Boiler Plant Equipment

A schematic of the boiler plant equipment is shown in Figure 19 .

Boiler Design: The boiler design consists of four modules; the modularized design provides for a maximum of shop fabrication and assists in meeting the turn-down requirements for the plant. Each module includes four primary fluidized bed combustors, each containing a separate boiler function -- one bed for the pre-evaporator, two beds for the superheater, and one bed for the reheater. Evaporation takes place in the water walls. All of the boiler heat transfer surface is immersed in the beds, except for the water walls. There is no convection heat transfer surface since the maximum allowable bed temperature is less than the state-of-the-art gas turbine temperature. The fluidized bed combustors are stacked vertically because of advantages in gas circuitry, steam circuitry, and pressure vessel design to achieve deep beds. Each module contains a separate fluidized bed or carbon burn-up cell to complete the combustion of carbon elutriated from the primary beds. A simplified drawing of a module is shown in Figure 20 . The 318 MW plant module is rail-shippable and can be shop-fabricated. The 635 MW plant module is designed to be shipped in sections, each shop-fabricated.

Fluidized Bed Combustors: The primary beds for the 318 MW plant are approximately 5 ft x 7 ft. The bed depths are approximately 12 feet -- sufficient for the required heat transfer surface. The carbon burn-up cell (CBC) is approximately 2 ft x 7 ft. The CBC contains no submerged surface in the bed.

Heat Transfer Surface: The submerged tube bundles are formed by vertical tube platens or planes, each platen a continuous boiler tube in a serpentine arrangement. A platen is schematically represented in Figure 20. The heat transfer surface can be viewed as horizontal tubes. The pre-evaporator and reheater contain 1-1/2-inch diameter tubes; the evaporator water walls and reheater bed contain 2-inch diameter tubes.

Dwg. 2965A06

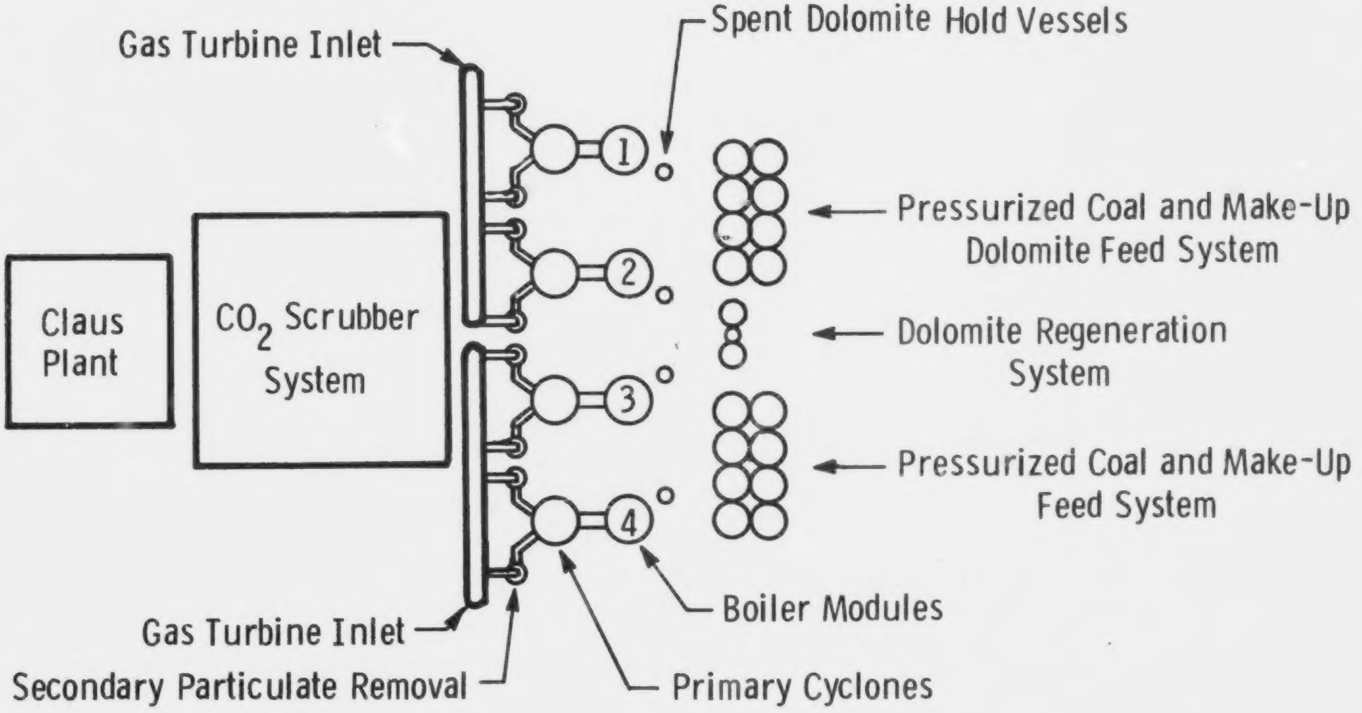
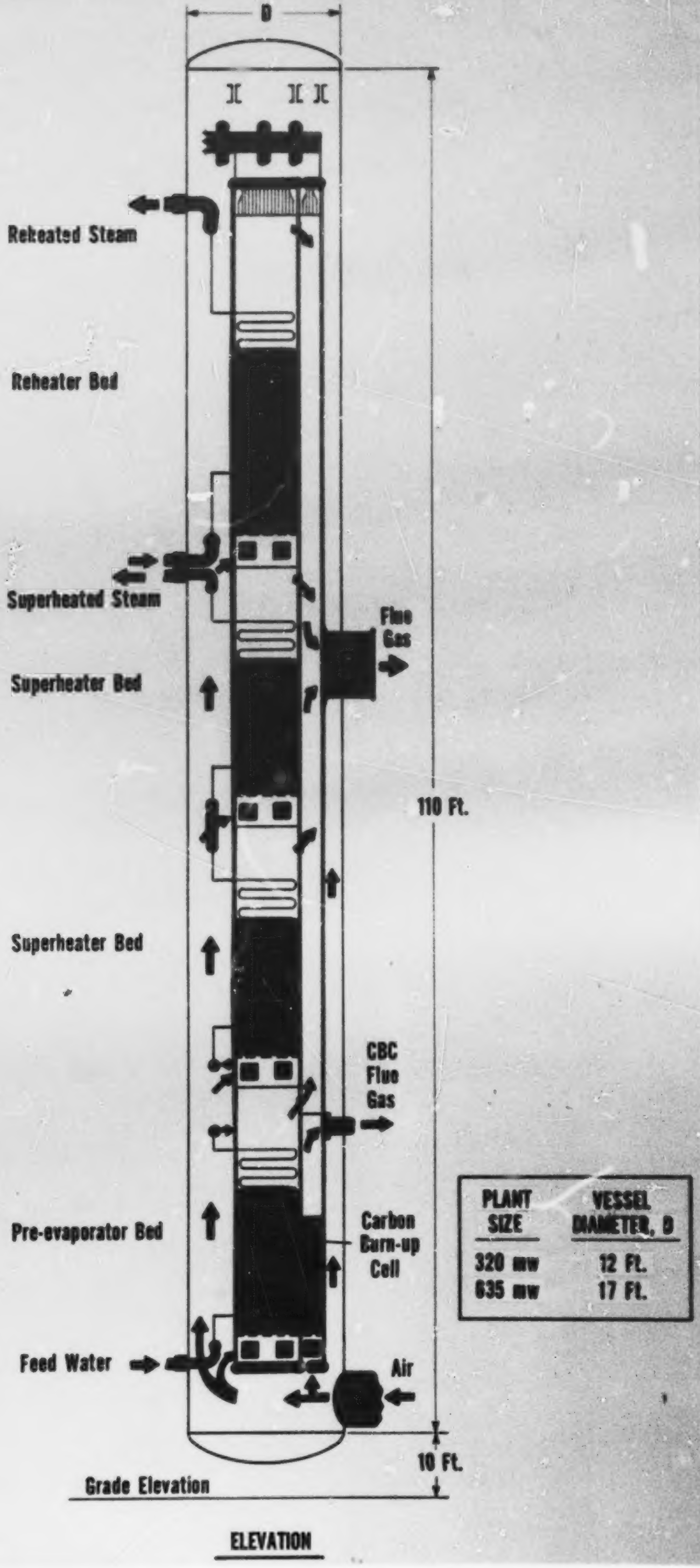

Spent Dolomite Hold Vessels
Gas Turbine Inlet
Pressurized Coal and Make-Up Dolomite Feed System
Claus Plant
CO_2 Scrubber System
Dolomite Regeneration System
Pressurized Coal and Make-Up Feed System
1
2
3
4
Boiler Modules
Gas Turbine Inlet
Secondary Particulate Removal
Primary Cyclones

Fig. 19 —Pressurized fluidized bed boiler plant equipment layout



PLANT SIZE	VESSEL DIAMETER, D
320 mw	12 Ft.
635 mw	17 Ft.

Fig. 20-Pressurized Fluidized Bed Steam Generator Module

]

The horizontal tube rows are 1-1/2 inches apart, in the pre-evaporator and superheater, 2 inches apart in the reheater, and the tubes are alternately spaced 7 inches in each row.

Steam Circulation: Once-through water circulation is employed to permit the use of horizontal boiler tubes in the beds. Feedwater enters the module near the bottom and flows upward through the pre-evaporator tube bank. Evaporation starts in the uppermost loops of this bank, and the mixture of water and steam flows into the first of four tube wall circuits. After each circuit the mixture is transported to the bottom of the next through unheated downcomers. Thus, the two-phase flow in heated tubes is always upwards, which prevents phase separation. Saturated steam leaves the fourth wall circuit and flows through the two superheater beds in series and then to the high-pressure steam turbine. The steam returns to the reheat bed between the high- and low-pressure steam turbines.

Air Circuits: Combustion air is taken from the gas turbine compressor exit to the pressure vessel and is distributed to the various beds in the module by an internal manifold formed by the volume between the water tube walls and the pressure vessel. Air dampers are provided to control the flow to the plenum chamber below each of the fluidized-bed distributor plates. The carbon burn-up cell has a separate, direct air supply connection to the plenum below the bed.

Products of Combustion: The products of combustion from the primary beds leave the tube wall enclosure through tube screens located near the top of the freeboard volume. The flue gases are collected in a 2 ft x 7 ft exhaust mainfold formed by tube walls with one side common with the bed enclosure. This is the only convection heat transfer surface in the boiler module. Near the middle of the module, an insulated pipe carries the flue gases from the water wall passage through the pressure vessel to the first-stage particulate separator located outside the module.

The flue gases from the carbon burn-up cell are segregated from those from the primary beds. A separate insulated pipe leads

Preceding page blank

from the carbon burn-up overhead out through the pressure vessel to join the primary flue gas pipe downstream of the first-stage particulate separator.

Solids Handling: Each primary bed has four injection points for pneumatically feeding coal into a tube-free space above the distributor plate. Make-up dolomite is fed in along with coal.

Each bed is equipped with one nearly vertical pipe, at a point about four feet below the top of the tube bank, which removes the spent dolomite from the bed for regeneration. Each bed also has one inlet pipe located about four feet above the air distributor plate for pneumatically injecting the regenerated dolomite.

The carbon burn-up cell is similar to the primary beds in that it has four injection points for the carbon-rich solids collected in the primary cyclones, one withdrawal pipe for spent dolomite, and one return pipe for regenerated dolomite.

Dolomite Regeneration/Sulfur Recovery System: A two-step, reduction/steam - CO_2 oxidation reaction scheme was selected for regenerating the sulfated dolomite from the boiler modules. A flow diagram of the system is shown in Figure 21 .

The spent dolomite from the pressurized fluidized bed boiler is regenerated to half calcined dolomite, $[CaCO_3+MgO]$. Sulfur, recovered as H_2S, is sent to a Claus plant where elemental sulfur is produced. Three main process vessels are required: a coal combustor or gas producer, a calcium sulfate reducer, and a hydrogen sulfate generator. Primary reactions occurring in the coal combustor are:

(1) $C + 1/2\ O_2 \rightarrow CO$

(2) $C + H_2O \rightarrow CO + H_2$.

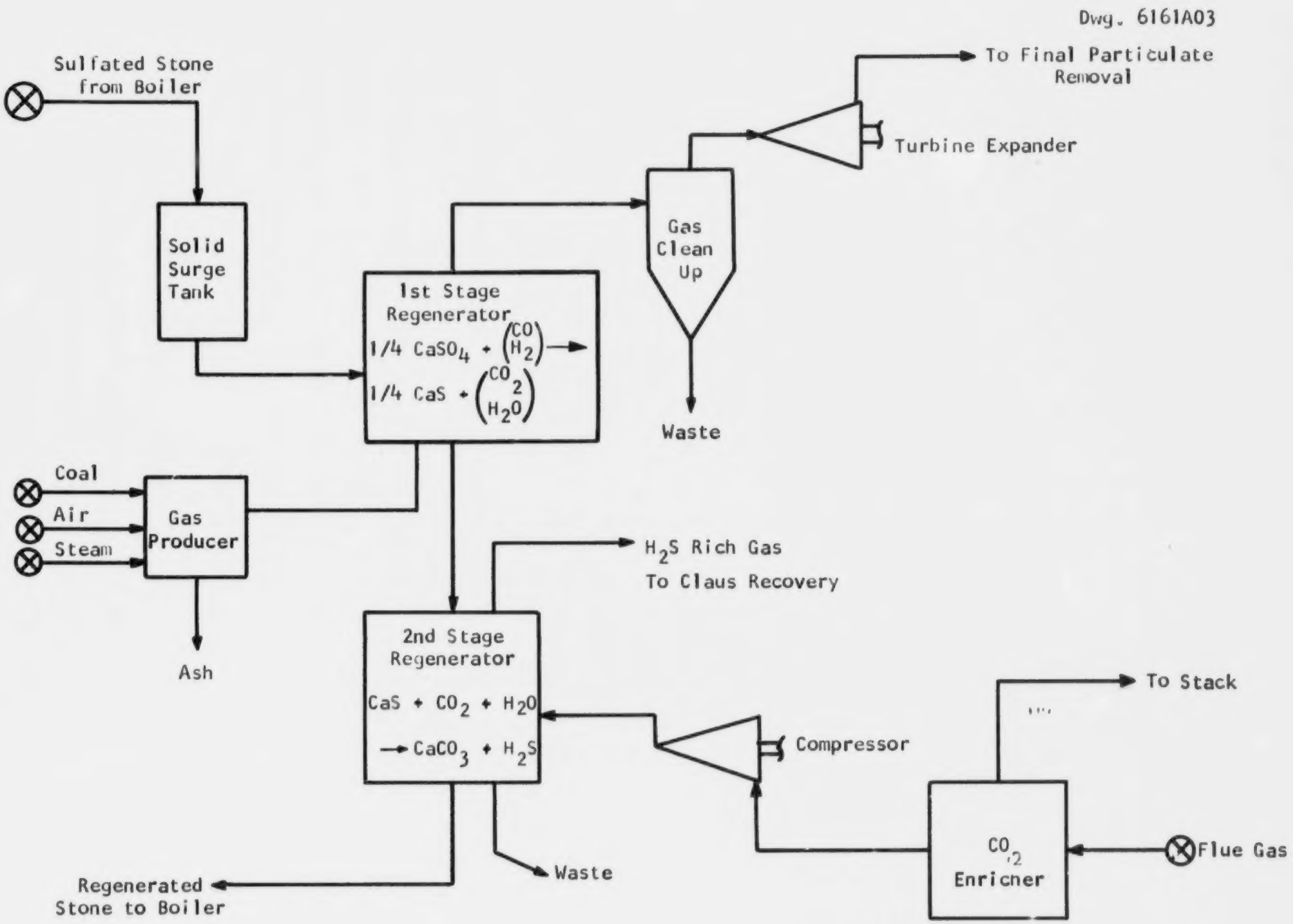

Dwg. 6161A03
Sulfated Stone from Boiler
Solid Surge Tank
1st Stage Regenerator
1/4 $CaSO_4$ + $\begin{pmatrix}CO\\H_2\end{pmatrix}$ →
1/4 CaS + $\begin{pmatrix}CO_2\\H_2O\end{pmatrix}$
Gas Clean Up
Waste
Turbine Expander
To Final Particulate Removal
Coal
Air
Steam
Gas Producer
Ash
H_2S Rich Gas To Claus Recovery
2nd Stage Regenerator
CaS + CO_2 + H_2O → $CaCO_3$ + H_2S
Compressor
To Stack
CO_2 Enricner
Flue Gas
Regenerated Stone to Boiler
Waste

Fig. 21–Pressurized regeneration schematic

The coal combustor can be replaced by a fuel oil or gas-fired burner operated under reducing conditions.

Calcium sulfate is converted to calcium sulfide in the $CaSO_4$ reducer vessel. This vessel operates at 800°C (∿1500°F) and ∿8 atmospheres pressure. Reactions occurring in this vessel are:

(3) $[CaSO_4 + MgO] + 4CO \rightarrow [CaS + MgO] + 4CO_2$

(4) $[CaSO_4 + MgO] + 4H_2 \rightarrow [CaS + MgO] + 4H_2O$

(5) $[CaO + MgO] + CO_2 \rightarrow [CaCO_3 + MgO]$

(6) $CO + H_2O \rightarrow CO_2 + H_2$.

Reduced solids flow through a stand pipe leg into the H_2S generator vessel, where steam and carbon dioxide convert calcium sulfide to calcium carbonate. This vessel, operating at 600°C (1100°F) and ∿12 atmospheres pressure produces a gas 23% H_2S (dry basis). High hydrogen sulfide in the reactor effluent is thermodynamically favored by high pressure. Primary reactions occurring in this vessel are:

(7) $[CaS + MgO] + H_2O+CO_2 \rightarrow [CaCO_3 + MgO] + H_2S$

(8) $[CaO + MgO] + CO_2 \rightarrow [CaCO_3 + MgO]$.

In addition to the process vessels, two auxiliary systems are required. Carbon dioxide feed to the H_2S generator is obtained by stripping a flue gas side stream in a conventional hot carbonate or monoethanolamine (MEA) absorber system and regenerating the absorbent by steam stripping the CO_2 from it. A conventional Claus plant converts hydrogen sulfide produced in the H_2S generator to elemental sulfur.

Auxiliary Equipment

Solids Handling: The coal and dolomite handling system includes conventional receiving, storage and conveying facilities. Coal and make-up dolomite are dried to < 3% moisture in a fluidized bed dryer and crushed to -1/4 inch in a reversible hammermill. The drying operation is required for operation of the pressurized feed system.

Solids Feeding: The coal and dolomite pressurizing and feeding system includes surge bins, lock hoppers, fuel injectors, and pneumatic transport lines to each bed. The coal feed system is illustrated in Figure 22 . A fluidized bed fuel distributor is used to feed and meter the coal and dolomite to each bed.

Particulate Removal: The particulate removal system in the combined-cycle plant with fluidized-bed boilers has three functions: to recover most of the unburned fuel in the solids elutriated from the primary beds for recycle to the carbon burn-up cell; to reduce the concentration of particulates in the gas stream going to the gas turbine to a level below that at which turbine blade erosion is a problem; and to control the emission of particulates to the atmosphere.

The first-stage collector is a conventional cyclone separator. Four cyclones in parallel are used for each boiler module and are enclosed in a single pressure vessel.

The second stage collector is a tornado separator of the type shown in Figure 23 . All particles larger than five microns are removed in this collector. Two of these collectors are used in parallel for each boiler module. Each unit has its own pressure vessel. The arrangement of the boiler modules with the first and second-stage particulate separators is shown in Figure 24 .

Power Generation Equipment

Gas Turbine - Generator: Two gas turbine modules are used with the four-module boiler system.

The high-pressure fluidized bed boiler is the combustor for the gas turbine, so provision must be made in the gas turbine design for removing the air from the compressor discharge and returning the hot gases to the turbine inlet. No industrial and utility gas turbines manufactured in the United States have external combustors.

In this study of combined cycle plants using fluidized bed boilers, two Westinghouse gas turbine models have been specified. In

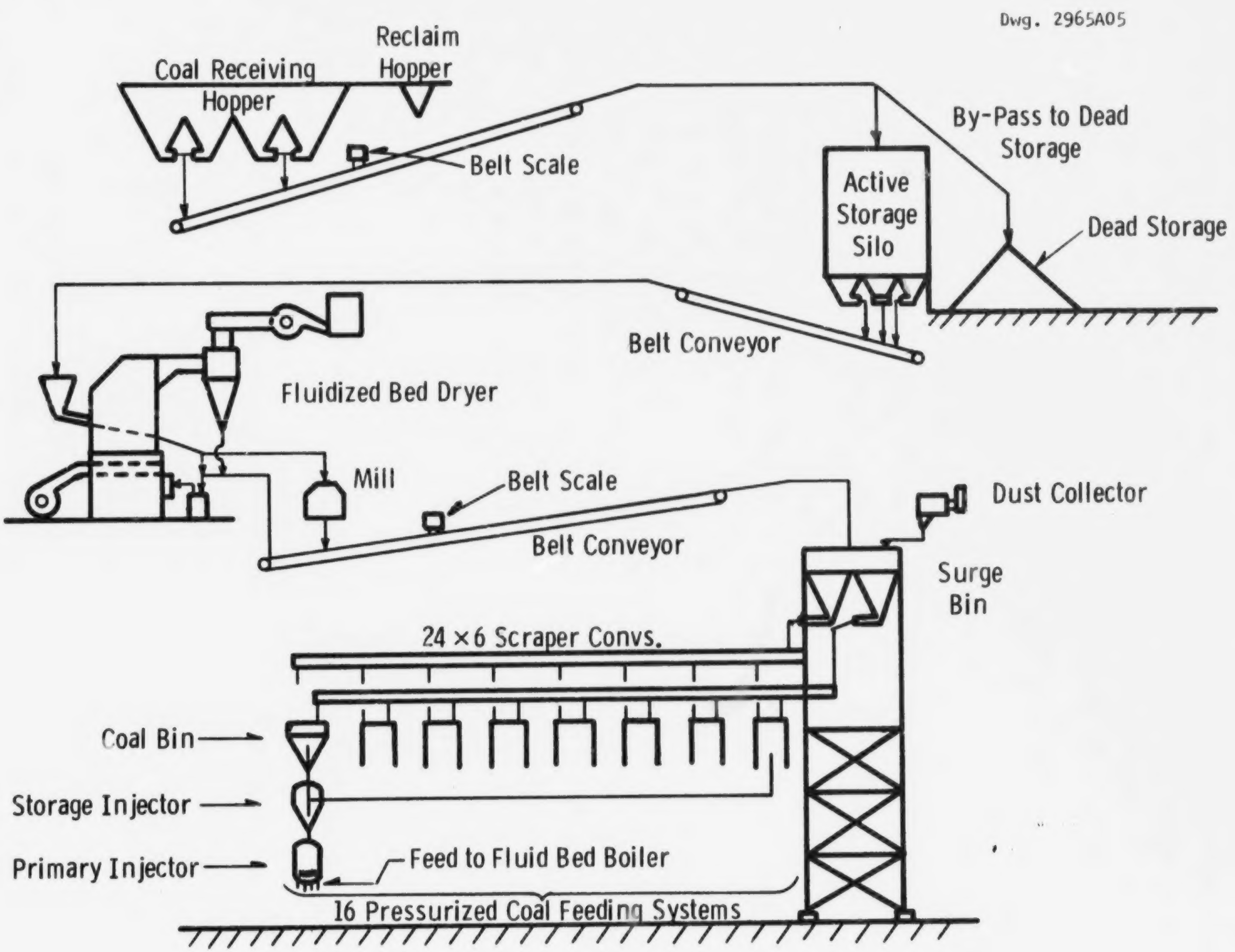


Fig. 22 —Coal handling and feed system schematic

Dwg. 6164A12

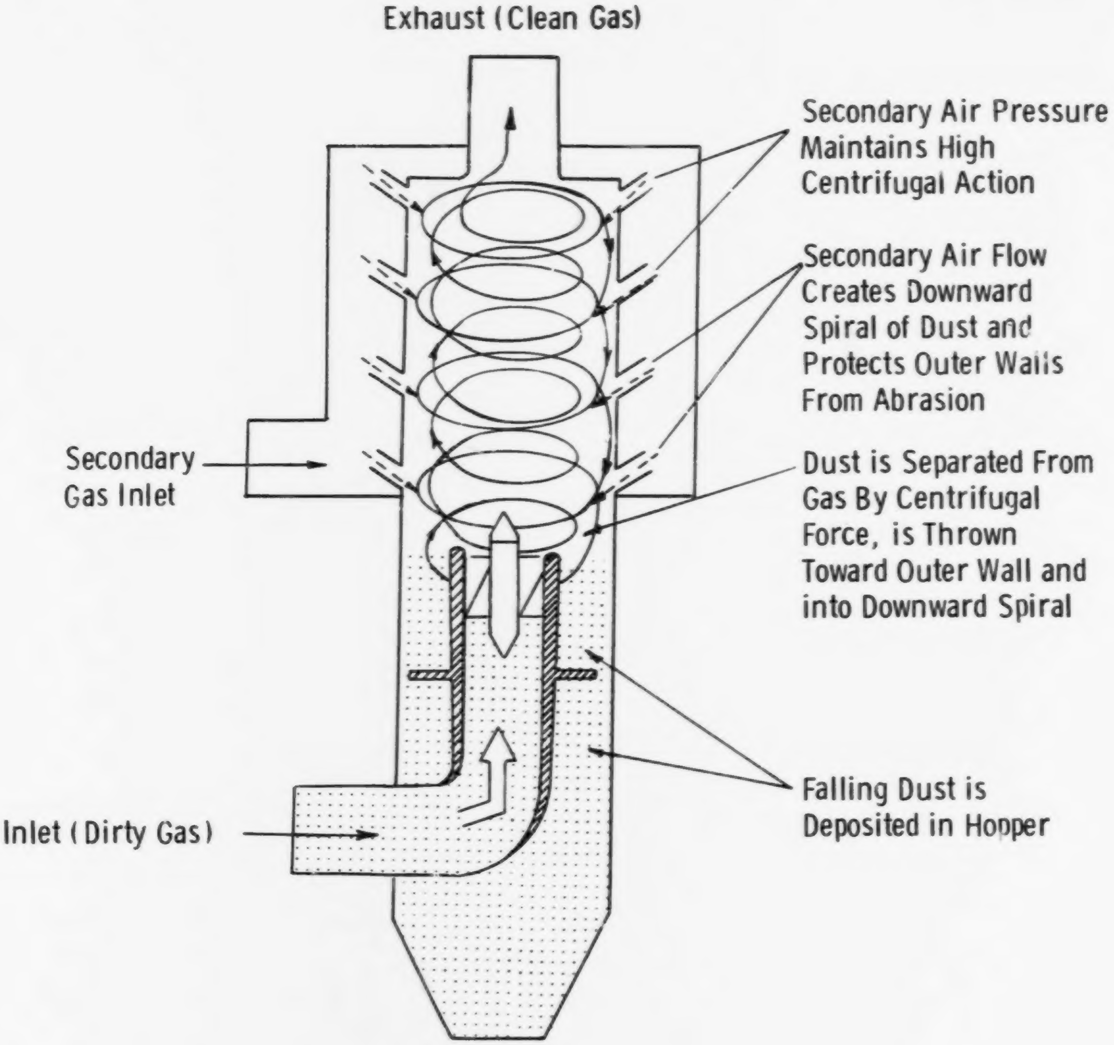

Exhaust (Clean Gas)
Secondary Air Pressure Maintains High Centrifugal Action
Secondary Air Flow Creates Downward Spiral of Dust and Protects Outer Walls From Abrasion
Secondary Gas Inlet
Dust is Separated From Gas By Centrifugal Force, is Thrown Toward Outer Wall and into Downward Spiral
Falling Dust is Deposited in Hopper
Inlet (Dirty Gas)

Fig. 23 — Operation of Aerodyne particulate separator

Dwg. 2965A02

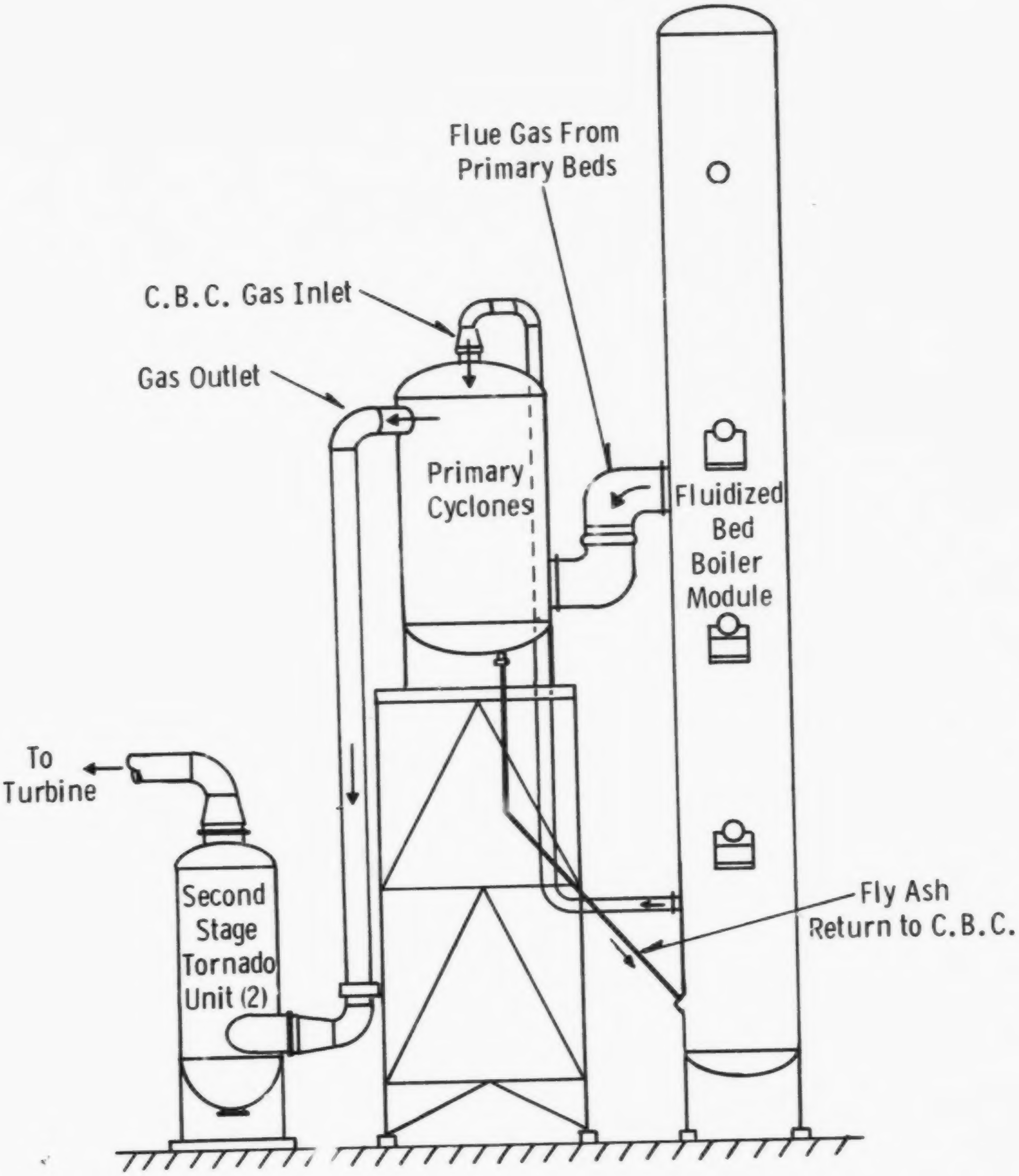


Fig. 24 —Particle collection equipment

the preliminary design of a high-pressure boiler for a 318 MW plant, two Westinghouse W251A gas turbines are used. In the 635 MW plant, for which plant layout and cost estimates were made, two Westinghouse W501A gas turbines are used. The Westinghouse Small Steam and Gas Turbine Division made a preliminary design of a modified W501A gas turbine for use with a high-pressure fluidized bed boiler and estimated the cost of manufacturing and developing this modified gas turbine design. The design is shown in Figures 25 and 26 . The gas manifold system has 16 concentric air and hot gas pipes which lead from the unit housing between the compressor exit and the turbine inlet to two vertical external manifolds. Separate connections for the air and the hot gas are provided at these external manifolds. A crossover pipe between the two manifolds is provided for the hot gas. The hot gas pipes terminate at the turbine inlet in 16 sectors which completely fill the turbine inlet annulus, thus eliminating the need for an internal hot gas manifold.

An internal manifold with one or more connections may be feasible for use at turbine inlet temperatures over 1600°F. Such a transition system could be less complex and possibly less expensive than the one proposed. However, a substantial amount of development effort would be required to obtain an adequate internal manifold design for this temperature level, whereas the external manifold design presented herein is more nearly a state-of-the-art design.

Steam Turbines: The steam conditions assumed are 2400 psig/ 1000°F/1000°F and 3 in. Hg back pressure. The steam turbine for this plant would be a 3600 rpm tandem compound unit with high-pressure, intermediate-pressure, and low-pressure components. The low-pressure end would be four flow exhaust with 28-1/2-inch last stage blades for a 635 MW plant. All four boiler modules would serve one steam turbine with a rating of 530 MW - 600 MVA.

Stack Gas Coolers: A conventional heat recovery system is used to recover the sensible heat from the gas leaving the gas turbine. The stack gas coolers are used to preheat the feedwater.

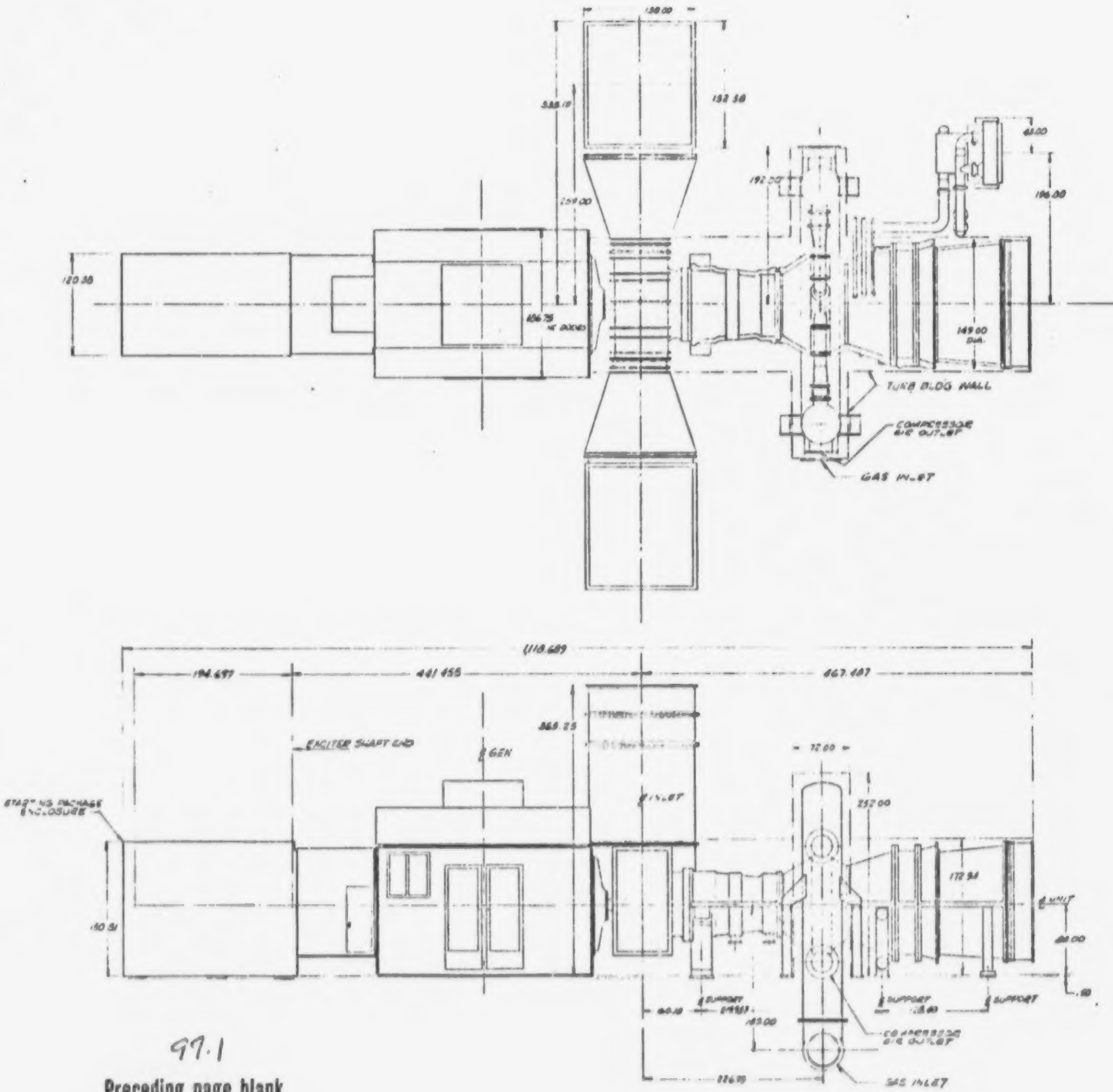
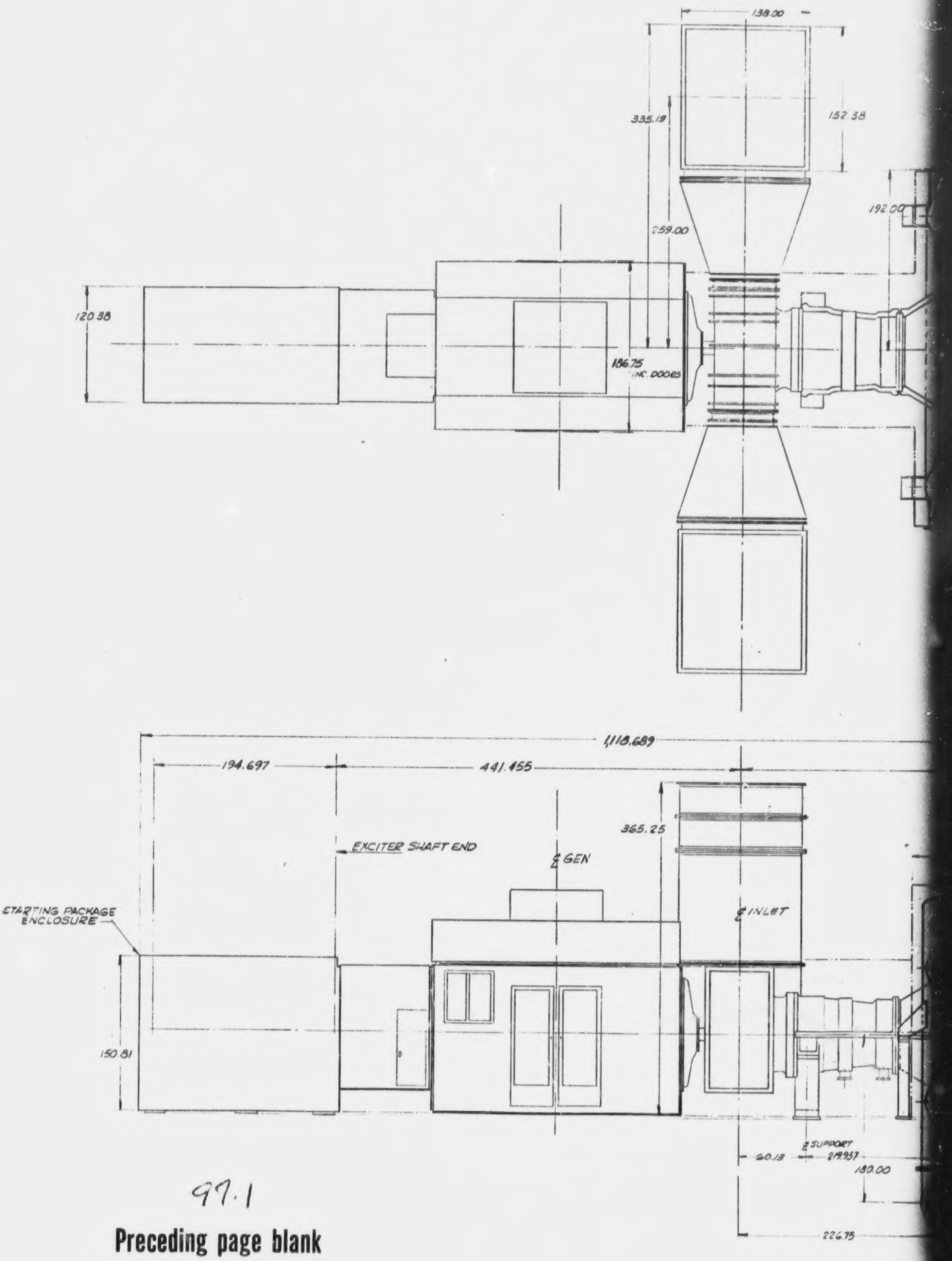


Fig. 25—Plan and elevation of W501 gas turbine modified for external combustion.

Preceding page blank



97.1

Preceding page blank

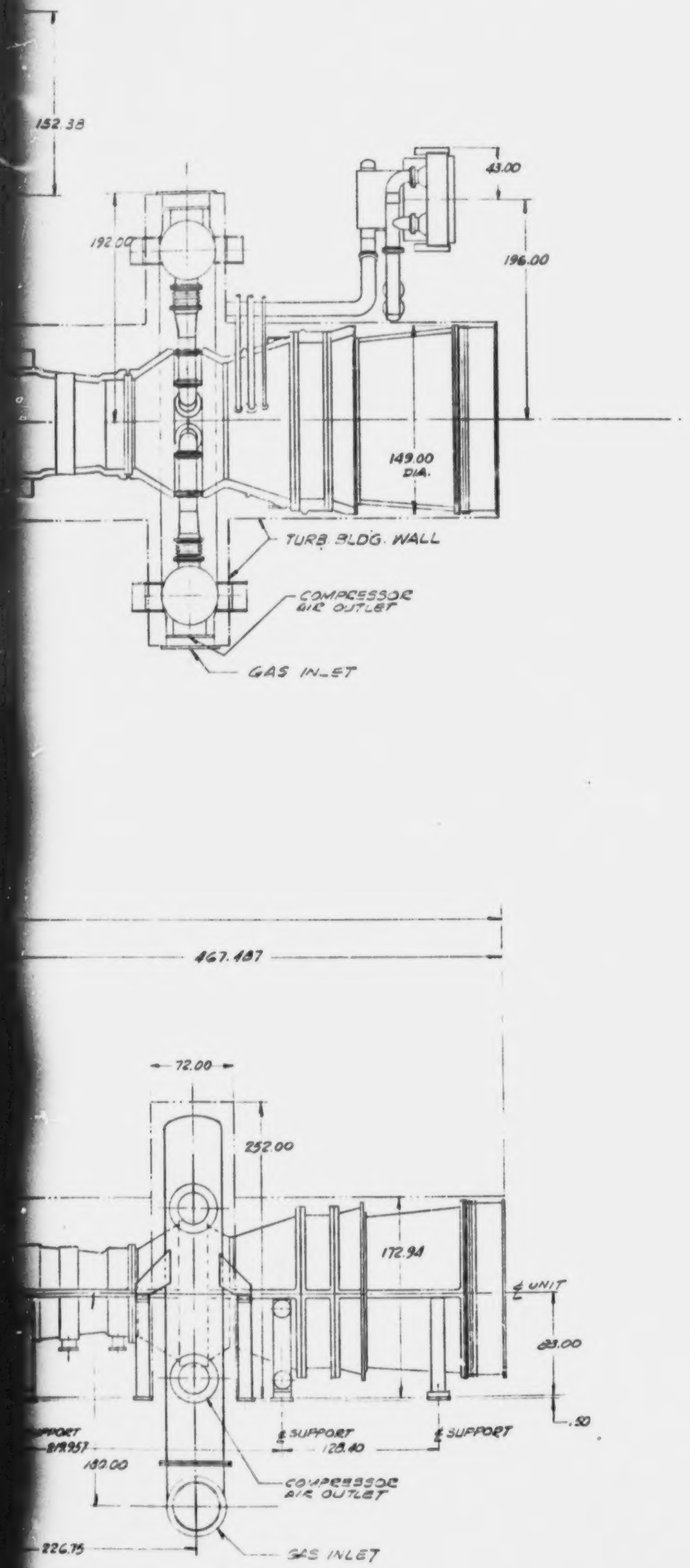


Fig. 25—Plan and elevation of W501 gas turbine modified for external combustion.

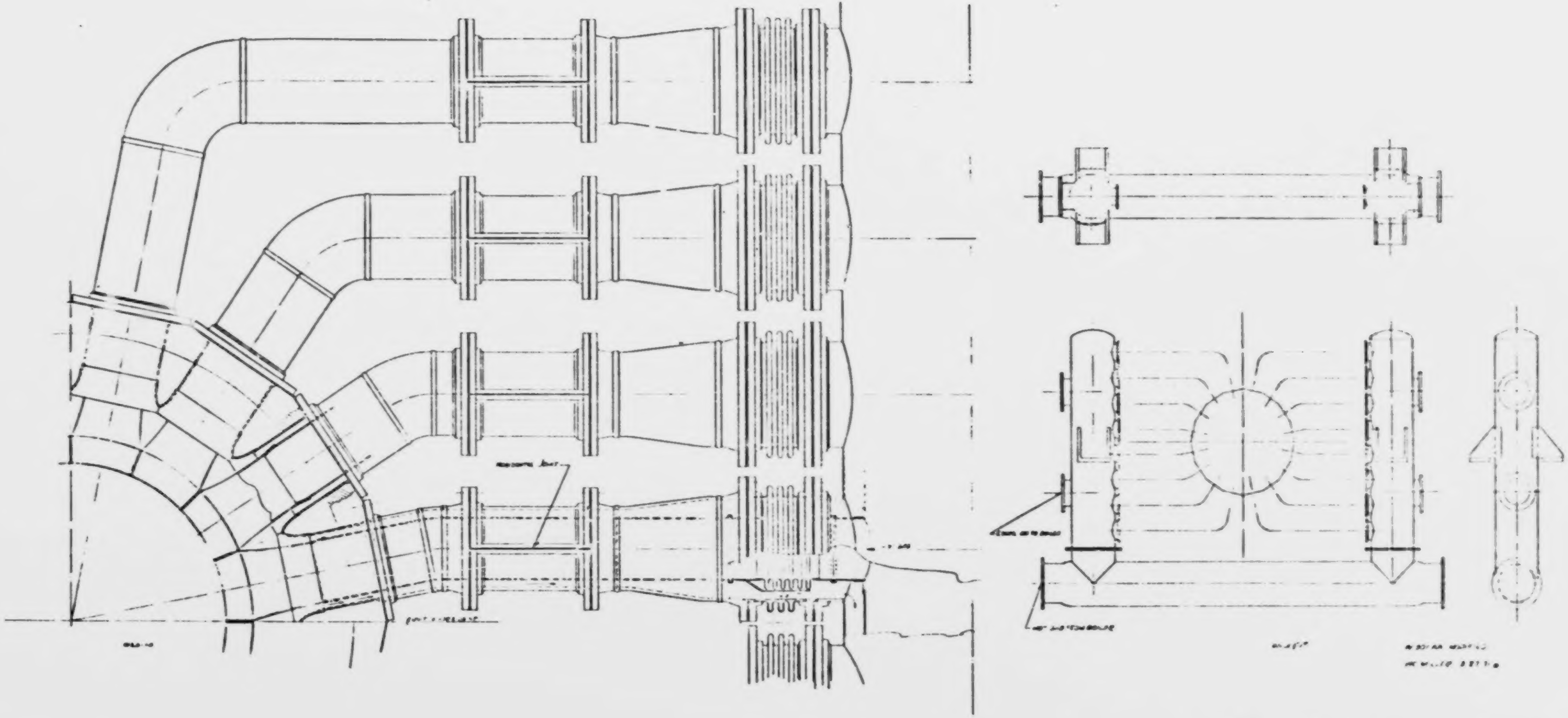


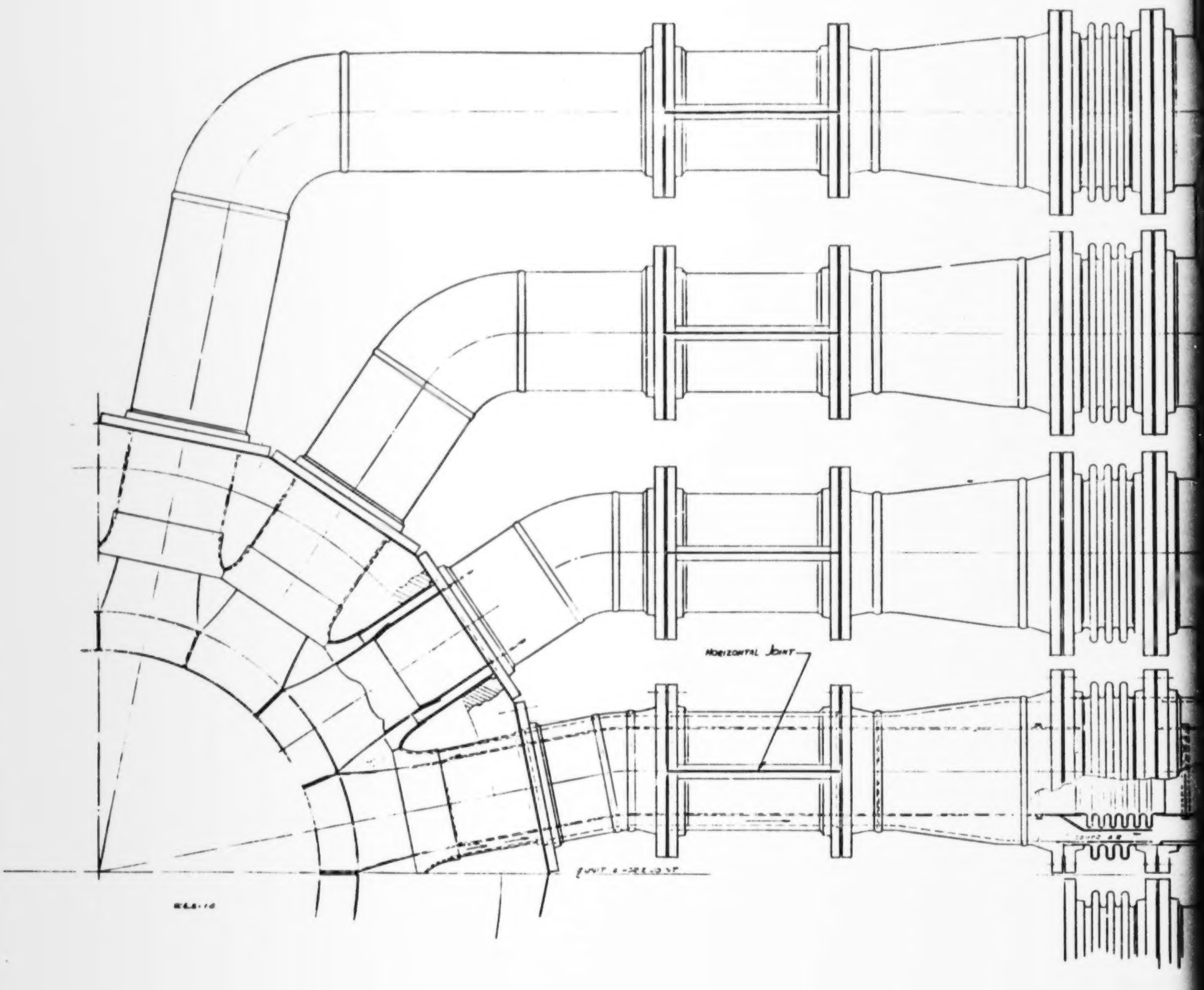
Fig. 26—Detail of piping arrangement for modified W501 gas turbine.

99.1

99.2

99.3

Preceding page blank



Preceding page blank

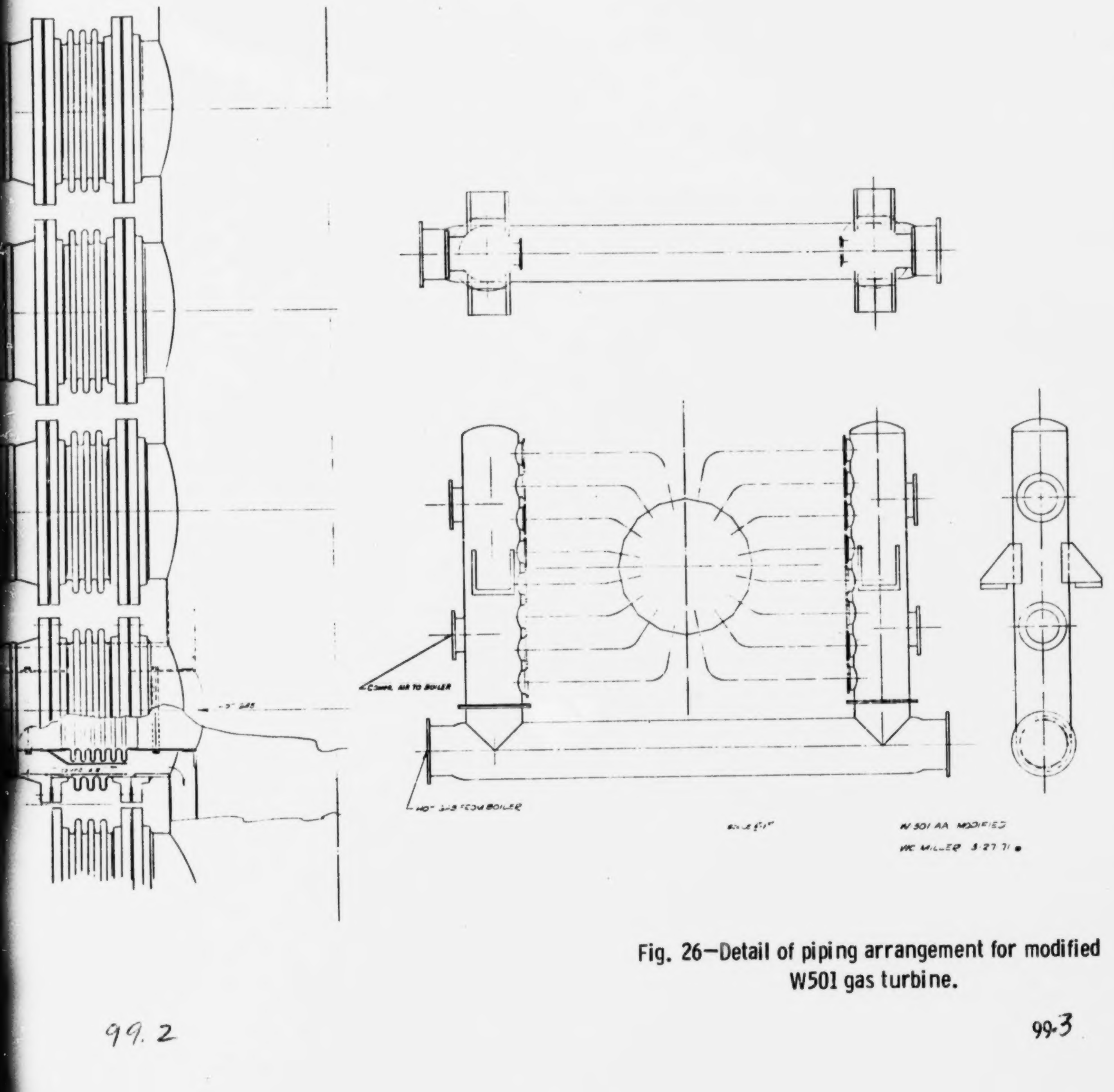


Fig. 26—Detail of piping arrangement for modified W501 gas turbine.

Controls and Instrumentation

A composite flow diagram for the high-pressure fluidized bed boiler system is shown in Figure 27. The control system for this plant is designed to perform the following functions:

- Maintain steam header pressure to the turbine at the desired value by regulation of the turbine governor valve
- Maintain steam header temperature at the turbine at the desired value by regulation of the fuel input to the beds
- The boiler feedwater flow is set by the load demand from the dispatcher.

Many of the plant subsystems are automated, e.g., the maintenance of solid levels in feeder bins. Other functions are manually controlled, e.g., the sorbent recycling rate to the beds wherein a monitor sounds an alarm when the recycle rate is too low or too high. Details on the controls for the boiler, boiler auxiliaries, power equipment, and lists of the instrumentation required for control and monitoring are presented in Volume II.

Plant Layout

United Engineers and Constructors was subcontracted to prepare a plant layout for a 635 MW pressurized fluidized bed boiler power plant. A hypothetical site on a large river in the Eastern United States was assumed. A plot plan and plant elevation are shown in Figures 28 and 29.

A temperature-enthalpy diagram for the pressurized boiler combined cycle power system is shown in Figure 30 . Gas temperatures, bed temperatures, steam temperatures and tube wall temperatures throughout the system at full load are shown on this diagram. It also shows how heat from the fuel is distributed among each of the boiler functions, the gas turbine expander, and the heat recovery exchangers.

Preceding page blank

Preceding page blank

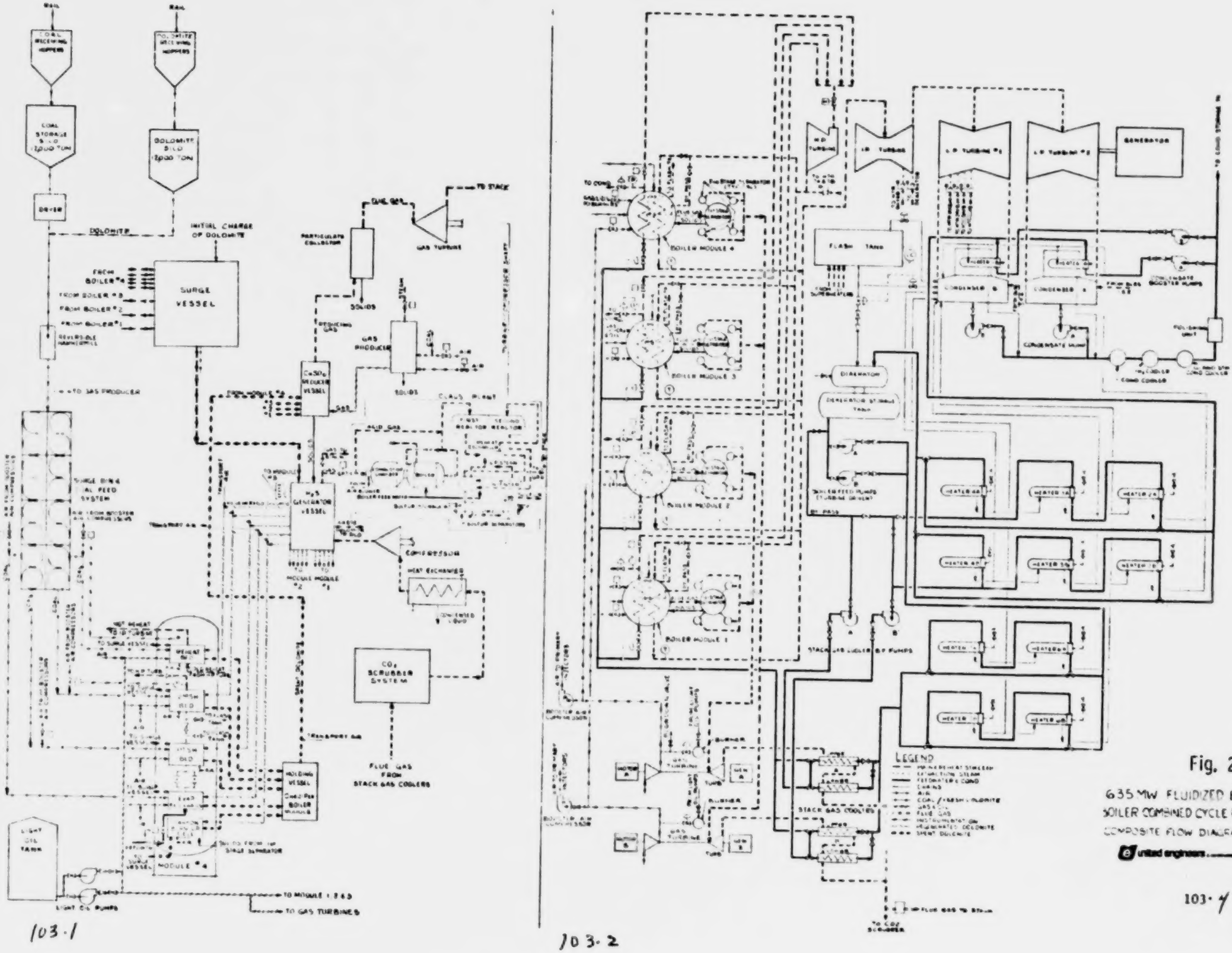


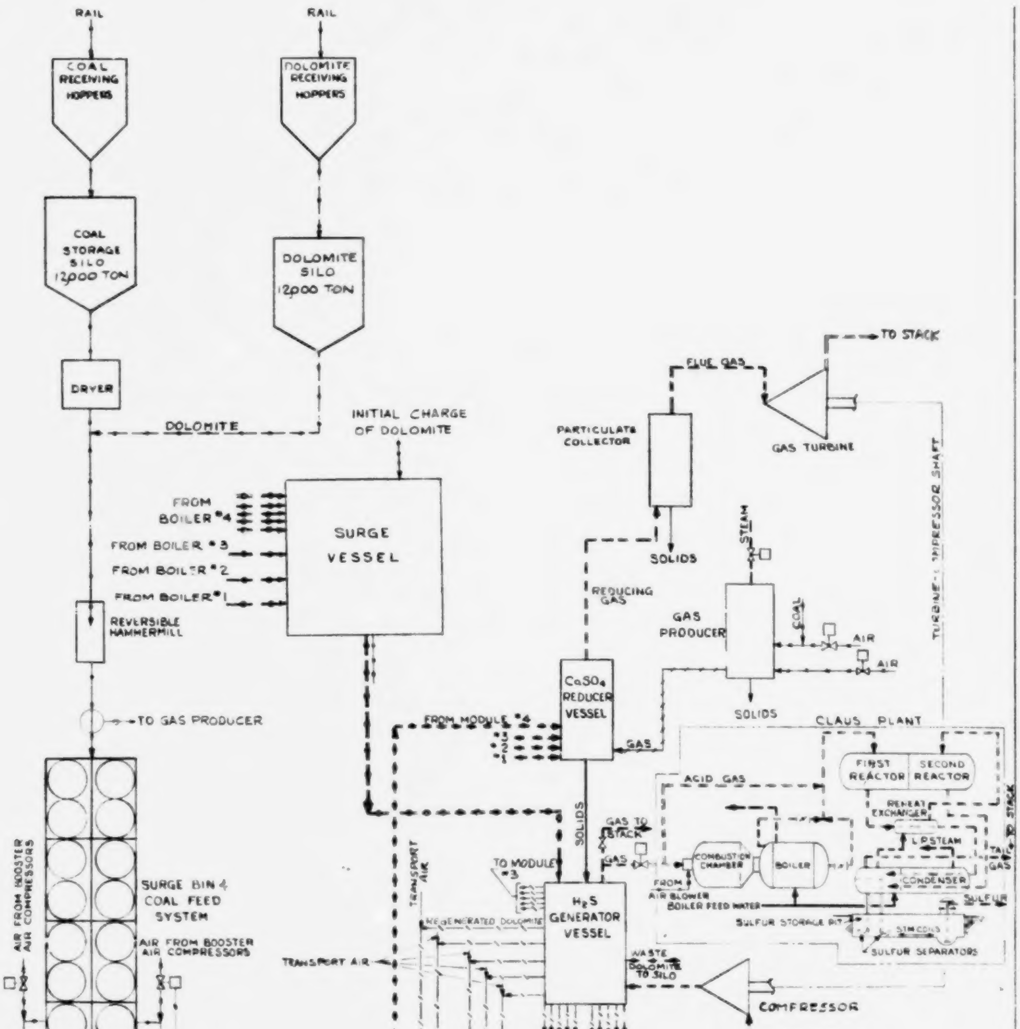
Fig. 27

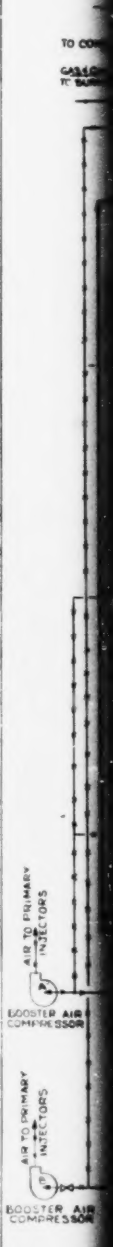
635 MW FLUIDIZED BED BOILER COMBINED CYCLE PLANT

COMPOSITE FLOW DIAGRAM

united engineers

Preceding page blank





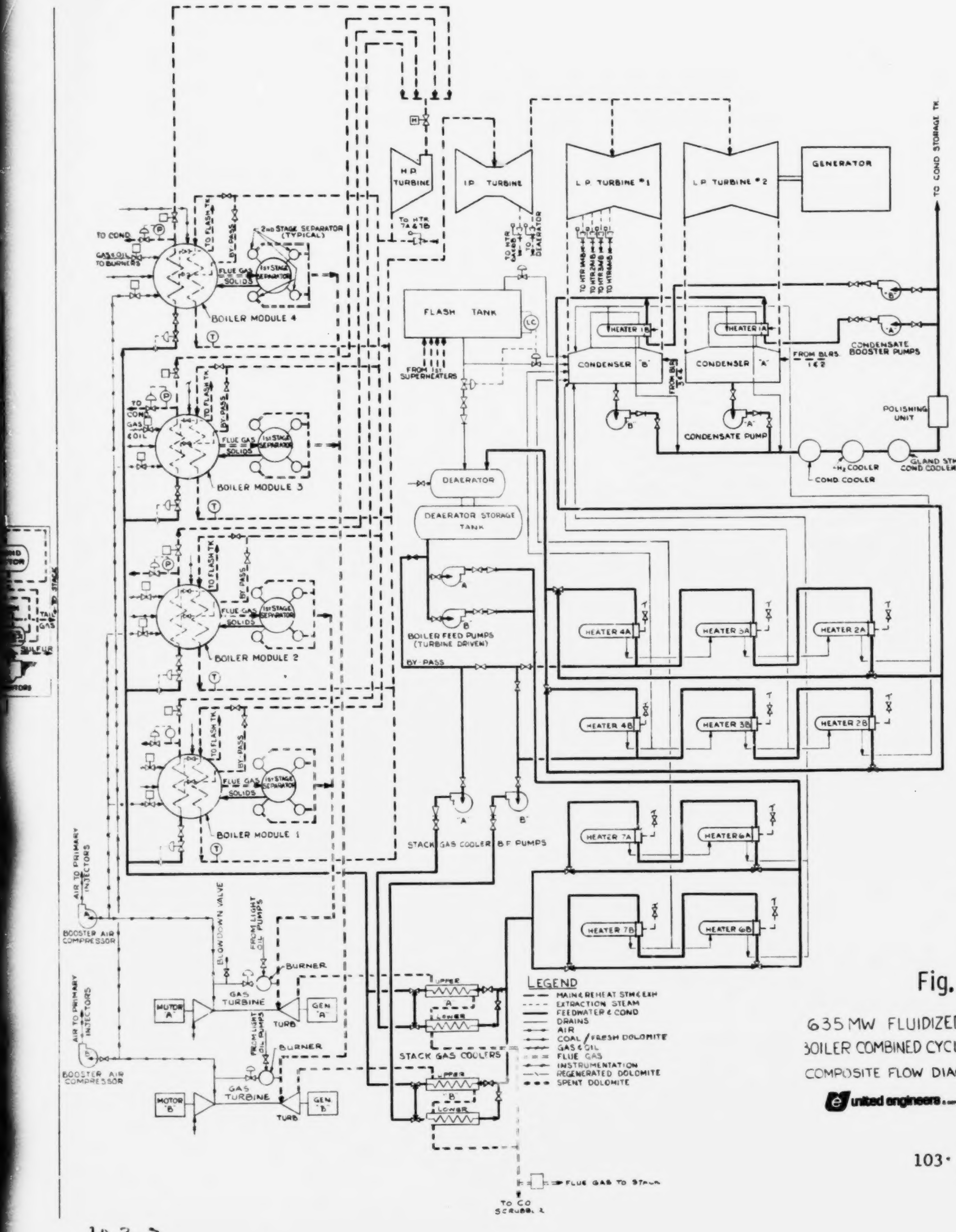
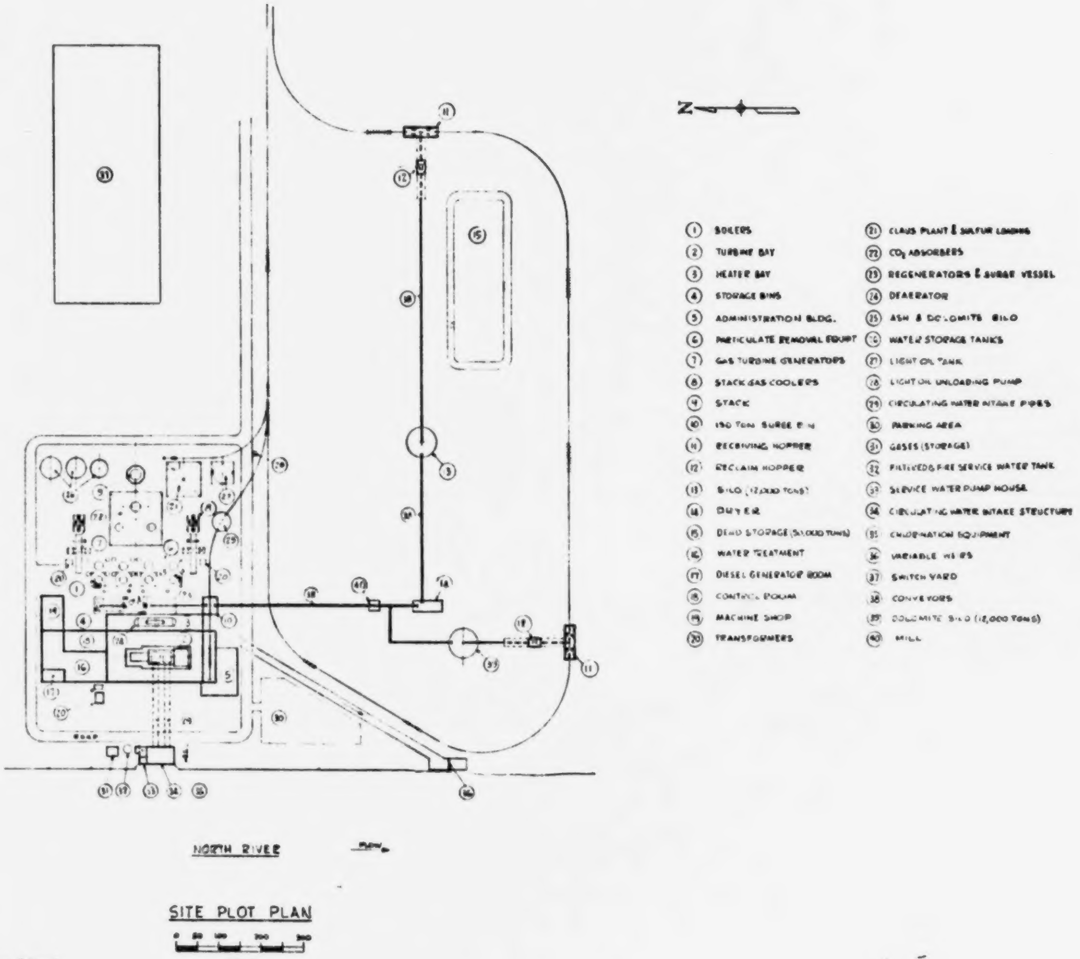


Fig. 27

635 MW FLUIDIZED BED BOILER COMBINED CYCLE PLANT COMPOSITE FLOW DIAGRAM

united engineers & constructors inc.



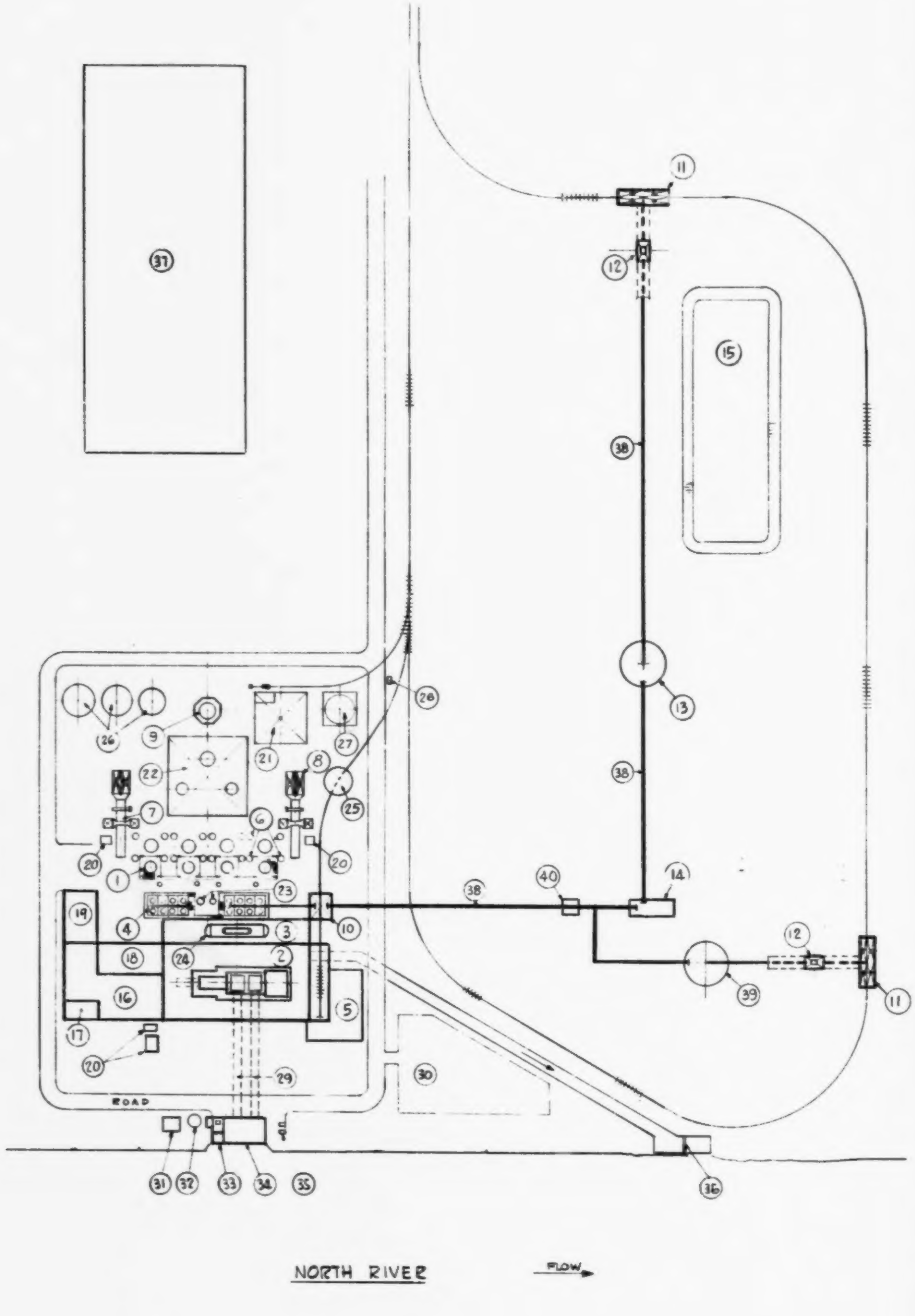
①	BOILERS	㉑	CLAUS PLANT & SULFUR LOADING
②	TURBINE BAY	㉒	CO_2 ABSORBERS
③	HEATER BAY	㉓	REGENERATORS & SURGE VESSEL
④	STORAGE BINS	㉔	DEAERATOR
⑤	ADMINISTRATION BLDG.	㉕	ASH & DOLOMITE SILO
⑥	PARTICULATE REMOVAL EQUIPT	㉖	WATER STORAGE TANKS
⑦	GAS TURBINE GENERATORS	㉗	LIGHT OIL TANK
⑧	STACK GAS COOLERS	㉘	LIGHT OIL UNLOADING PUMP
⑨	STACK	㉙	CIRCULATING WATER INTAKE PIPES
⑩	150 TON SURGE BIN	㉚	PARKING AREA
⑪	RECEIVING HOPPER	㉛	GASES (STORAGE)
⑫	RECLAIM HOPPER	㉜	FILTERED & FIRE SERVICE WATER TANK
⑬	SILO (12,000 TONS)	㉝	SERVICE WATER PUMP HOUSE
⑭	DRYER	㉞	CIRCULATING WATER INTAKE STRUCTURE
⑮	DEAD STORAGE (51,000 TONS)	㉟	CHLORINATION EQUIPMENT
⑯	WATER TREATMENT	(36)	VARIABLE WEIRS
⑰	DIESEL GENERATOR ROOM	(37)	SWITCH YARD
⑱	CONTROL ROOM	(38)	CONVEYORS
⑲	MACHINE SHOP	(39)	DOLOMITE SILO (12,000 TONS)
⑳	TRANSFORMERS	(40)	MILL

Fig. 28

635 MW FLUIDIZED BED BOILER COMBINED CYCLE PLANT
SITE PLOT PLAN

united engineers

Preceding page blank



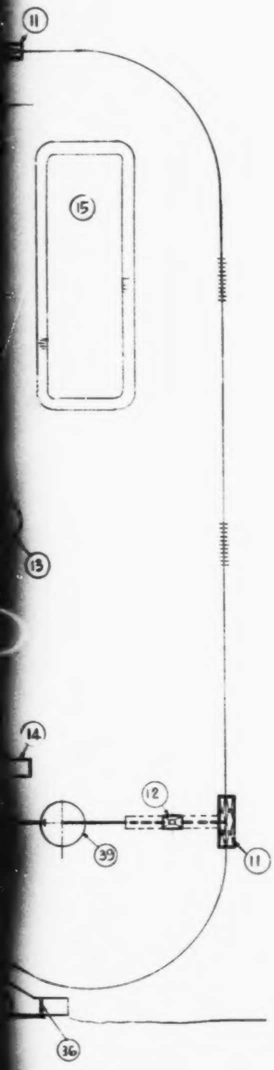
SITE PLOT PLAN

0 50 100 200 300

SCALE

Preceding page blank

105.1



① BOILERS
② TURBINE BAY
③ HEATER BAY
④ STORAGE BINS
⑤ ADMINISTRATION BLDG.
⑥ PARTICULATE REMOVAL EQUIPT
⑦ GAS TURBINE GENERATORS
⑧ STACK GAS COOLERS
⑨ STACK
⑩ 150 TON SURGE BIN
⑪ RECEIVING HOPPER
⑫ RECLAIM HOPPER
⑬ SILO (12,000 TONS)
⑭ DRYER
⑮ DEAD STORAGE (50,000 TONS)
⑯ WATER TREATMENT
⑰ DIESEL GENERATOR ROOM
⑱ CONTROL ROOM
⑲ MACHINE SHOP
⑳ TRANSFORMERS
㉑ CLAUS PLANT & SULFUR LOADING
㉒ CO_2 ABSORBERS
㉓ REGENERATORS & SURGE VESSEL
㉔ DEAERATOR
㉕ ASH & DOLOMITE SILO
㉖ WATER STORAGE TANKS
㉗ LIGHT OIL TANK
㉘ LIGHT OIL UNLOADING PUMP
㉙ CIRCULATING WATER INTAKE PIPES
㉚ PARKING AREA
㉛ GASES (STORAGE)
㉜ FILTERED & FIRE SERVICE WATER TANK
㉝ SERVICE WATER PUMP HOUSE
㉞ CIRCULATING WATER INTAKE STRUCTURE
㉟ CHLORINATION EQUIPMENT
㊱ VARIABLE WEIRS
㊲ SWITCH YARD
㊳ CONVEYORS
㊴ DOLOMITE SILO (12,000 TONS)
㊵ MILL

Fig. 28

635 MW. FLUIDIZED BED
BOILER COMBINED CYCLE
PLANT
SITE PLOT PLAN

united engineers & constructors inc.

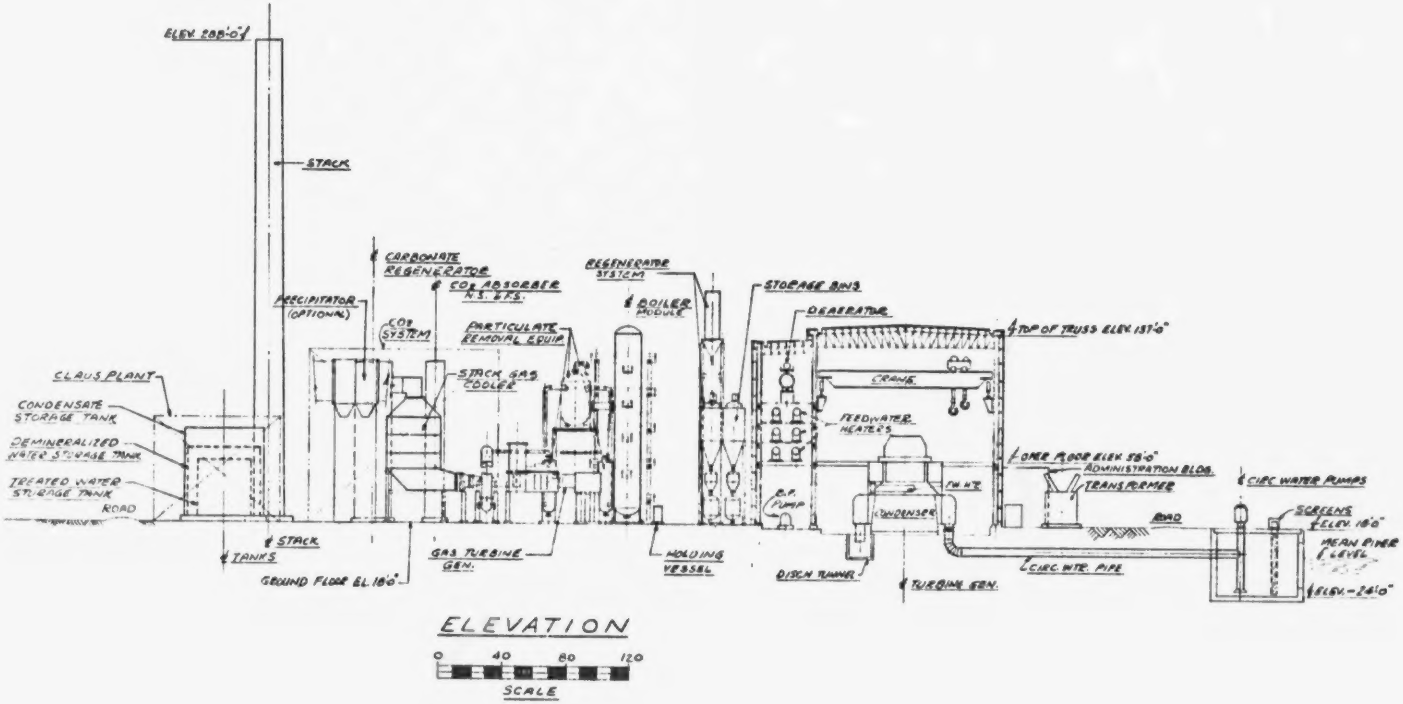
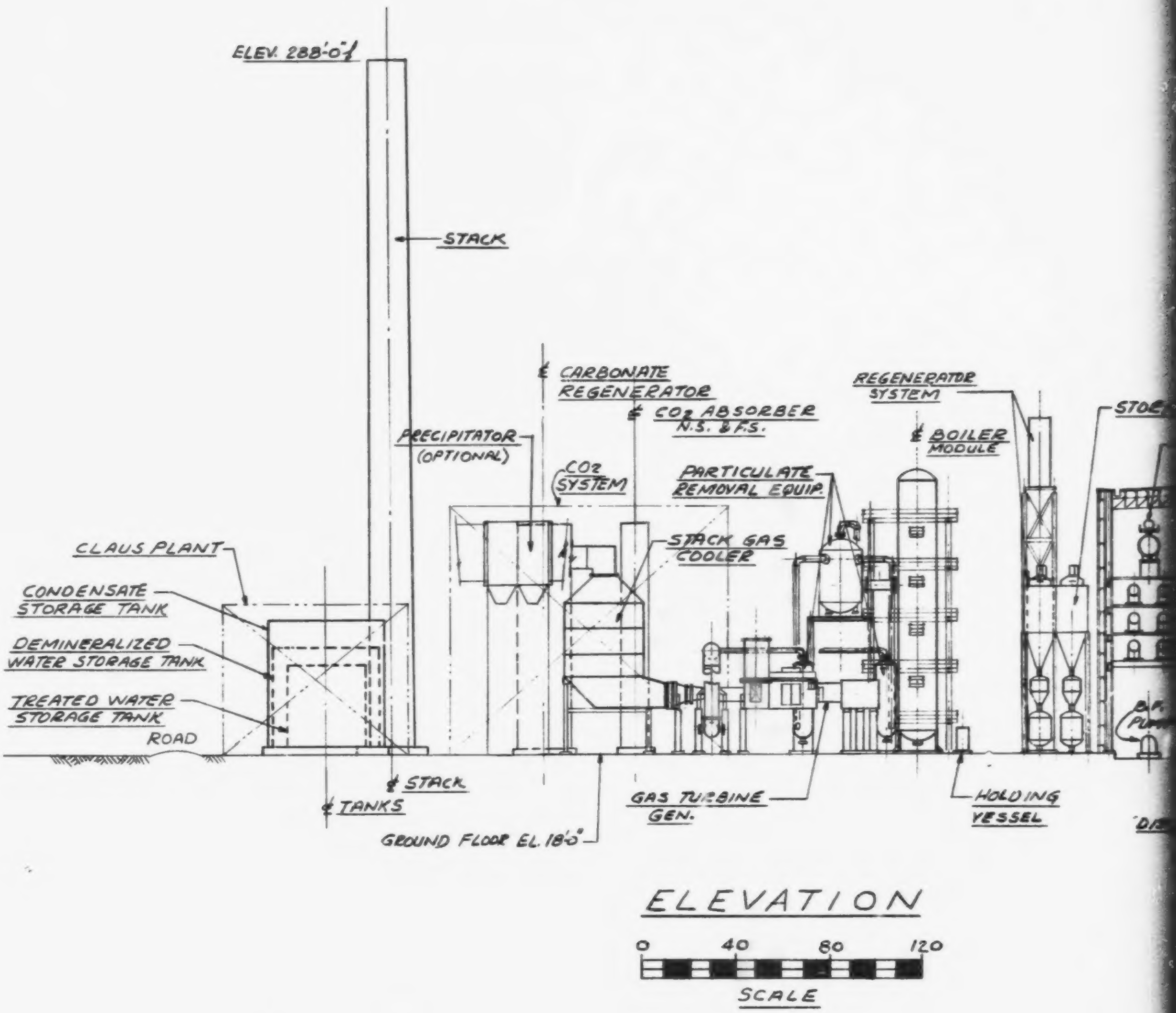


Fig. 29

635 M.W. FLUIDIZED BED BOILER
COMBINE CYCLE PLANT
ELEVATION

UNITED ENGINEERS & CONSTR. INC. PHILA, PENNA.

Preceding page blank



101.1

Preceding page blank

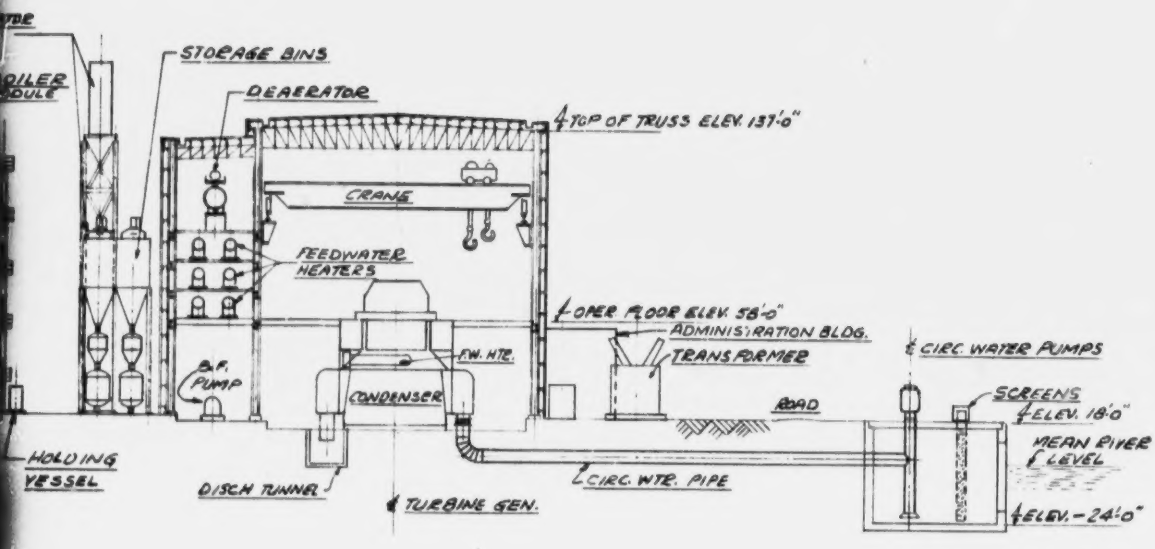


Fig. 29

635 M.W. FLUIDIZED BED BOILER
COMBINE CYCLE PLANT
ELEVATION
UNITED ENGINEERS & CONSTR. INC. PHILA., PENNA.

107.2

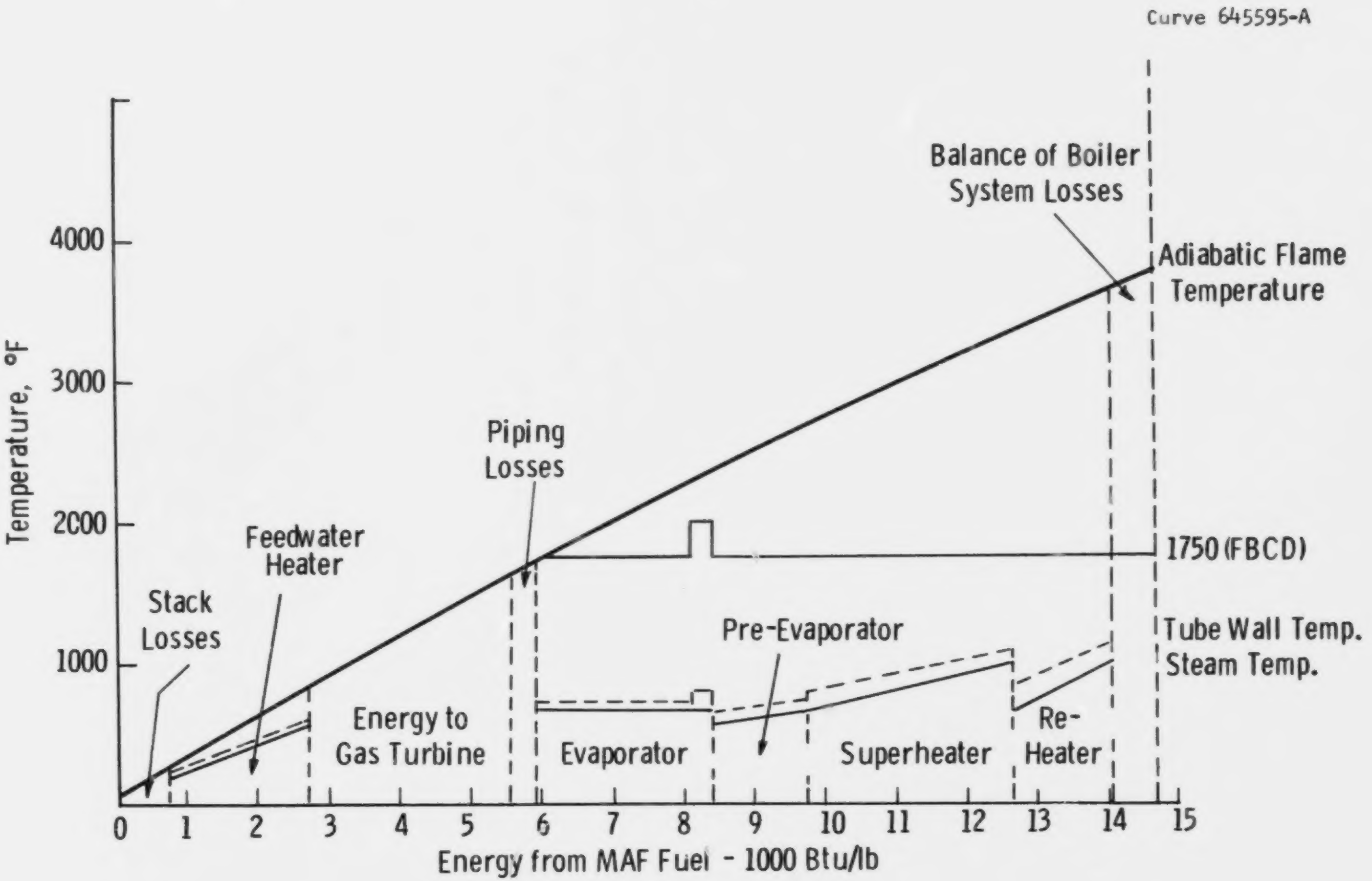


Fig. 30 —Temperature-energy diagram for pressurized utility boiler

Preceding page blank

Performance

Boiler Performance: Steam generator efficiency calculations are misleading in a combined cycle plant if the gas temperature leaving the steam generator is used to calculate the stack gas losses. The stack gas temperature should be used to calculate a combination boiler and gas turbine combustor efficiency. The calculated and estimated losses for the high-pressure fluidized bed boiler on this basis are as follows:

Component	Loss - %
Dry gas loss @ 275°F	3.88
Loss due to hydrogen and moisture in coal	4.14
Loss due to moisture to air @ 275°F	0.08
Radiation loss	0.15
Incomplete combustion	1.51
Solids sensible heat	0.11
Unaccounted for and manufacturer's margin	1.50
TOTAL	11.37

This gives a combustion efficiency of 88.6%

Gas Turbine Pressure Loss Effect: Boiler plant pressure drop has a small effect on plant capacity and heat rate. A change of one percent in pressure loss between the gas turbine compressor exit and the turbine inlet causes a 0.1% decrease in plant power and a 0.1% increase in plant heat rate. The reasons for this are:

- Only the gas turbine is directly affected, and it contributes only 17.5% of the plant power.
- A decrease in the gas turbine power results in higher gas turbine exit temperature and increased steam power.

Steam Turbine Condenser Pressure Effect: The steam turbine condenser pressure affects the plant capacity and heat rate. The condenser pressure will be determined by the heat rejection system. A power plant with cooling towers typically has a steam condenser pressure of 3 in. Hg. If the heat is rejected to a body of water, the pressure is typically 1-1/2 in. Hg. The plant performance for these two cases with a boiler efficiency of 88.6% is:

Condenser pressure - inches Hg	1-1/2	3
Plant power, MW	325.7	317.7
Plant heat rate, Btu/kWh	8853	9076

Part-Load Performance: It has been shown that the energy input to the boiler, the steam cycle power, and the gas turbine power in the combined cycle fluidized bed boiler are a function of the following four parameters:

- Air flow rate
- Fuel/air ratio
- Bed temperature
- Bed depth.

Three possible modes of load control for the combined cycle system with a fluidized bed boiler using different combinations of these parameters were identified. The characteristics of these modes, used singly or in combination, were determined and a preferred mode was selected.

In the preferred control mode, the depth of the fluidized beds and the gas turbine compressor air flow are held constant, while the fuel/air ratio to the beds and the bed temperatures are varied. Steam power decreases due to lower bed temperature, and gas turbine power decreases due to lower gas temperature. With a minimum bed temperature of 1300°F, a turn-down of approximately 50% is possible; and by using two gas turbine modules with one or more boiler modules per gas turbine module, the specified plant turn-down of 75% can be attained with no discontinuities in load.

Pollution Abatement: Emissions are considered for the total power plant. This includes potential emissions from coal drying, dolomite regeneration, and sulfur recovery, as well as the boiler modules. Emission projections from the plant are summarized in Table 20.

Overall regeneration performance, particularly with respect to sulfur removal efficiency, is difficult to predict precisely. The Claus plant, without tail gas clean-up, will recover 94 to 96% of the sulfur fed to it. Losses from the regenerator should amount to approximately 2 to 5% of the total sulfur (assuming gas leaving the reducer vessel has the equilibrium SO_2 concentration). Therefore, the overall sulfur recovery efficiency should be around 90% without tail gas clean-up from the Claus plant and 94 to 99% with tail gas clean-up.

The cost estimates for the various components of this regeneration system were obtained from the following sources. Detailed design information is given in Volume III.

solids feed system	Petrocarb
Claus plant	Ford, Bacon and Davis
CO_2 scrubber	Benfield Corporation
process vessels	Westinghouse Heat Transfer Division

Plant Performance: The full load heat rate for the site chosen is 8853 Btu/kW-hr. This corresponds to a back pressure of 1-1/2 in. Hg.,

TABLE 20

AIR EMISSIONS SUMMARY

	SULFUR DIOXIDE lb $SO_2/10^6$ Btu	NITROGEN OXIDES lb $NO_2/10^6$ Btu	PARTICULATE lb/10^6 Btu
BOILER PLANT(a) (Boilers and Coal Drying)	0.7	0.07-0.22	0.02-0.16(c)
DOLOMITE REGENERATION	0.1	---	---
SULFUR RECOVERY	0.1-0.2(b)	---	---
TOTAL	0.9-1.0	0.07-0.22	0.02-0.16

(a) Does not consider fugitive dust.

(b) Includes tail gas sulfur recovery processes (e.g., Ford, Bacon, and Davis' IFP Process) at a cost of $3/kW.

(c) The data indicate that uncontrolled fluidized bed boilers will emit significantly less fine (<10μm) material: ~10wt% vs 30 wt% for conventional plants. Thus, for a 8.5% ash coal, a conventional plant would emit ∿ 40 lb particulates < 10μm/ton coal and a FBB is projected to emit ∿ 30 lb ash and stone particulates <10μm/ton coal, without any particulate control.

combustion efficiency of 88.6%, and pressure losses in the gas turbine combustor loop of 7.5% of the total. The overall plant efficiency is 38.4% under these conditions.

Atmospheric Pressure Fluidized Bed Boiler Power Plant Design

The atmospheric pressure fluidized bed boiler is a potential replacement for conventional boilers. The power generation and electric equipment of a conventional power plant are not altered by using the new boiler concept. The preliminary design includes the boiler, solids handling, draft system, sulfur removal/recovery system, and instrumentation and control.

Boiler Plant Equipment

Boiler Design: The preliminary boiler design consists of an in-line arrangement of four separate modules of vertically stacked fluidized bed combustors. Each module contains six beds including a carbon burn-up cell, as illustrated in Figure 31 . Each bed performs a single boiler function -- two beds for evaporation, two for superheating, and one for reheating. The water walls used for enclosing the beds are used for evaporation. The feedwater is preheated in a convective surface above each bed. Horizontal tube bundles are used in all beds and for the convection passes. The submerged tubes have vertical and horizontal pitches of four inches. Two-inch tubes are used in the reheater bed and the convection passes. One- and one-half-inch tubes are used in the superheater and evaporator beds.

An internal common duct collects the flue gas with carbon-rich ash from the five primary fluidized beds and carries it to the primary cyclone separator. A separate duct located within the main flue gas duct carries the flue gas from the carbon burn-up cell to another dust collector.

Coal is pneumatically transported through 16 separate feed lines to each bed as a dilute phase of dried coal in 250°F air.

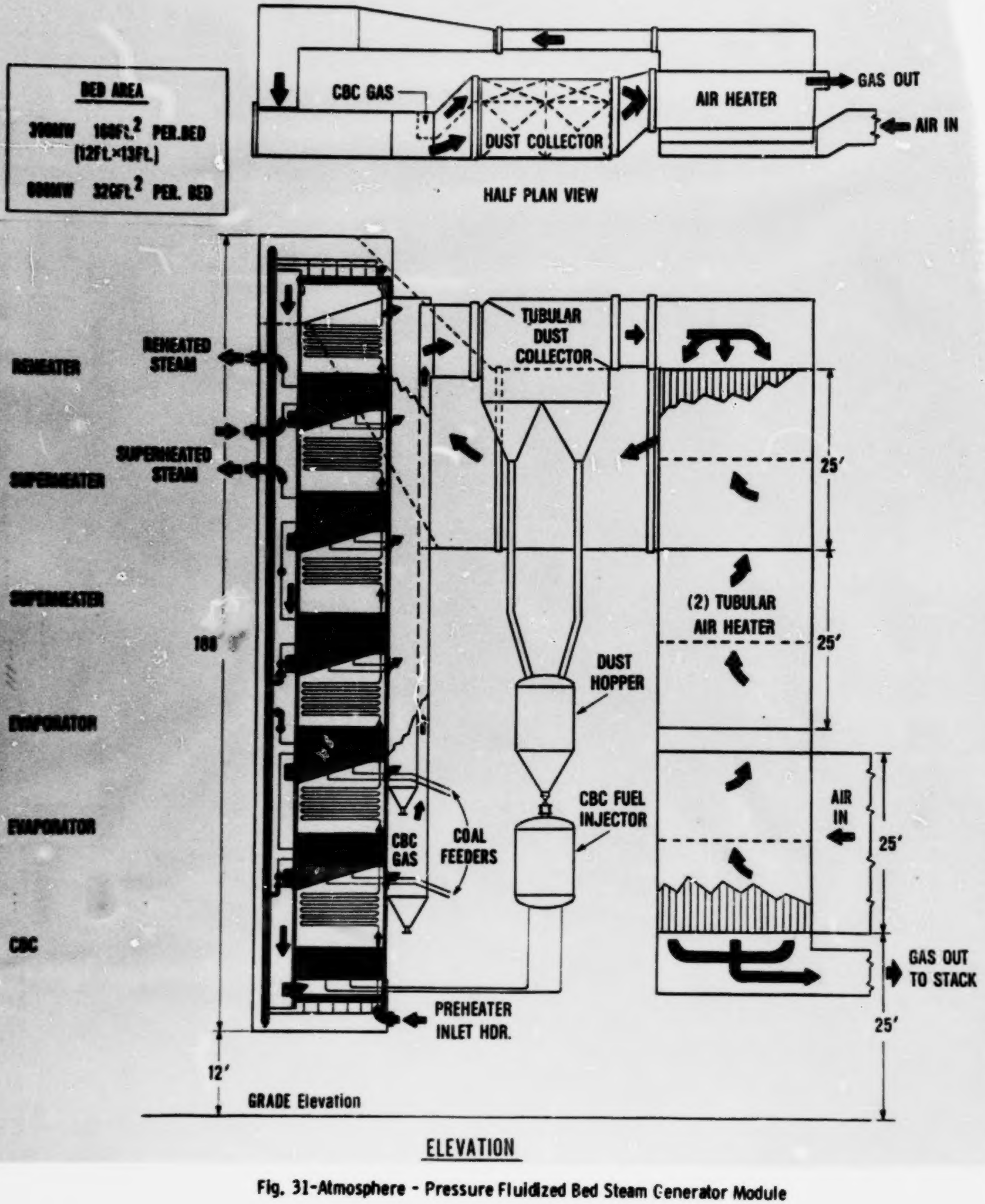


Fig. 31-Atmosphere - Pressure Fluidized Bed Steam Generator Module

The coal feed lines enter the gas duct from either side of the module, pass through the flue gas exit openings in the water wall, then up into the plenum chambers and through the grid plates. The coal is injected horizontally into a volume of the bed free of tube bundles. One coal injector is provided for each ten square feet of fluid bed surface. The recycle ash feed lines are brought into the module at a point below the carbon burn-up cell.

Limestone feeding into the fluidized beds falls into two categories: make-up feed and recycled limestone feed. The make-up limestone is fed into the beds along with the coal. Each bed is provided with one injection point for the regenerated limestone and one withdrawal point for the spent limestone.

Auxiliary Equipment

Solids Handling and Crushing: The coal and limestone handling system includes receiving, storage, crushing, and conveying facilities. Coal is crushed into 1/4 inch x 0 in a reversible hammermill and fed to 16 hoppers for injection to the boiler modules. Limestone may be purchased crushed to 1/4 inch x 0 or may be crushed on-site. The crushed make-up limestone is combined with the coal on the conveyor to the hoppers.

Solids Drying and Feeding: The coal and limestone feeding system includes hoppers for receiving coal from the coal handling systems, volumetric feeders, combination fluid bed dryers and distributors, dust collectors for the fluidizing air, primary air fans, and dilute phase coal transport lines to the individual coal injection points.

The high carbon content particulates elutriated from the primary beds are recovered by cyclones, collected in a dust hopper, and transferred to a fluid bed injector which meters the flow of solids to the carbon burn-up cell.

Draft Fans and Air Preheater: The secondary air enters the system at the forced draft fan and is heated to 735°F in the air preheater

Preceding page blank

from which it is fed into the internal air distribution duct. Air is metered by dampers into plenum chambers below each fluidized bed. A separate cool stream is taken off ahead of the air heater for the carbon burn-up cell. A tubular type of air preheater was selected over the somewhat less expensive regenerative type because of the severe leakage problem which could result from the use of a regenerative air preheater in combination with the high pressure drop fluidized bed and the forced draft fan.

Particulate Removal: The particulate removal system in the fluidized bed boiler has two functions: to recover most of the unburned fuel in the solids elutriated from the primary beds for recycle to the carbon burn-up cell, and to control the emission of particulates to the atmosphere.

There are two stages of particulate removal for the products of combustion from both the primary beds and the carbon burn-up cell. Multiclone collectors were selected for the first stage of both streams. These two collectors are physically integrated with the two gas and solids streams isolated so that the carbon-rich ash from the primary beds is not mixed with the spent ash from the carbon burn-up cell. The two gas streams are mixed after the multiclones, and an electrostatic precipitator is used to reduce the particulate concentration to meet emission standards.

Sulfur Removal/Recovery System

Sulfated limestone from the fluidized beds is regenerated by a direct reduction process. The calcium sulfate is converted back to CaO by reaction with a reducing gas:

$$CaSO_4 + \binom{CO}{H_2} \rightarrow CaO + SO_2 + \binom{CO_2}{H_2O}.$$

The regenerated limestone is returned to the boiler modules. The off-gas from the regenerator has a high SO_2 concentration (4 to 10% by volume) and is used to produce sulfur. A flow diagram of the process is shown in Figure 32 .

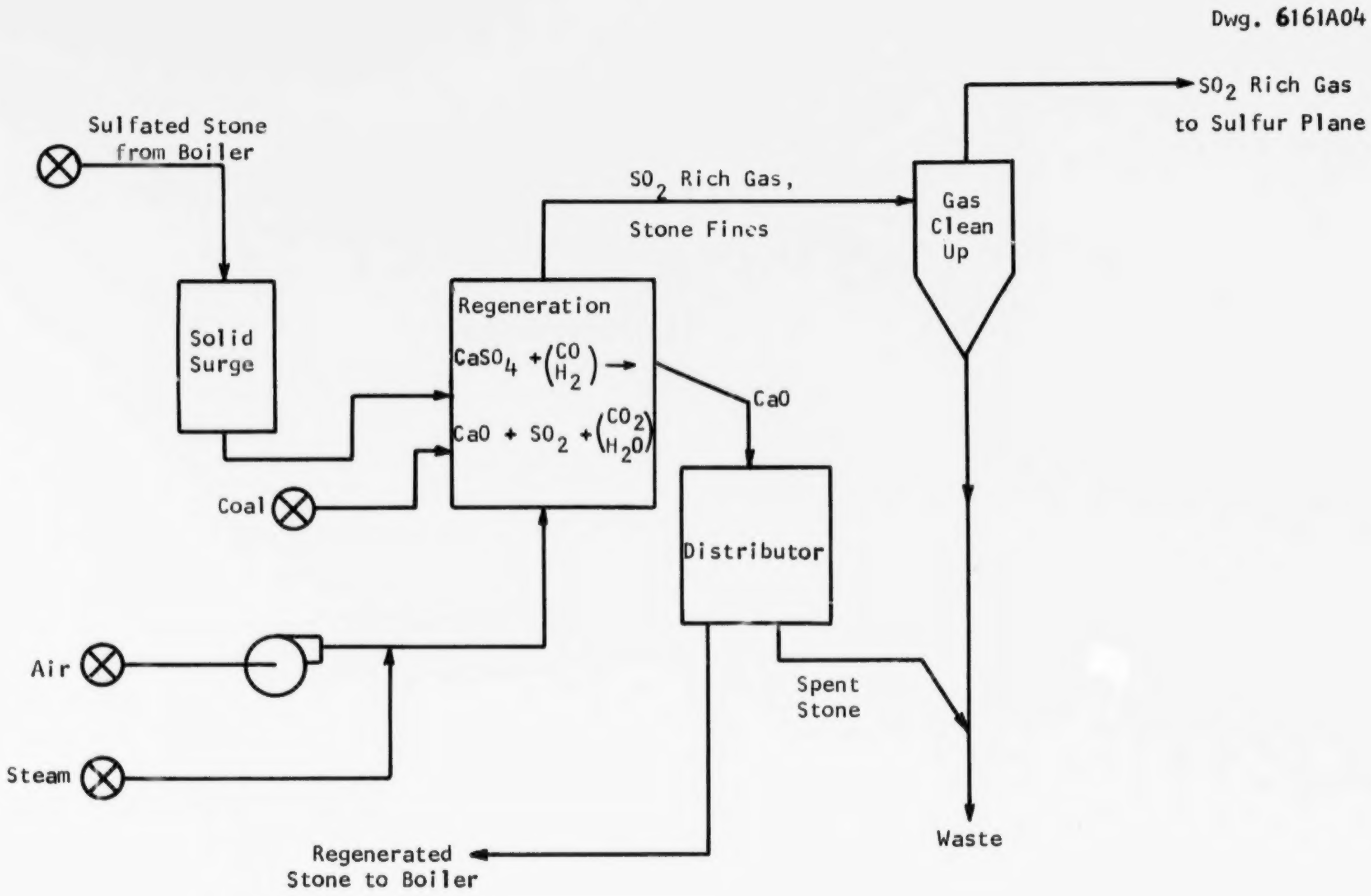

Dwg. 6161A04
Sulfated Stone from Boiler
Solid Surge
Coal
Air
Steam
Regeneration
$CaSO_4 + \binom{CO}{H_2} \rightarrow$
$CaO + SO_2 + \binom{CO_2}{H_2O}$
SO_2 Rich Gas,
Stone Fines
Gas Clean Up
SO_2 Rich Gas to Sulfur Plane
CaO
Distributor
Spent Stone
Waste
Regenerated Stone to Boiler

Fig. 32 —Atmospheric pressure regeneration schematic

Spent stone discharges from each bed into a hold vessel -- one hold vessel per boiler module. The stone is then pneumatically transported to the regenerator vessel using air as the carrier gas.

The regenerator vessel is a fluid bed reactor operating at one to two atmospheres and 2000°F. Coal is charged into the reactor bed. An air-stream mixture fluidizes the reactor bed and combusts coal to provide reducing gas for reduction of the $CaSO_4$.

Regenerated stone flows from the reactor vessel to a distributor vessel. Twenty-four lines return regenerated stone from the distributor to each bed in the boiler modules.

The hot regenerator top gas passes through a gas cooler and cleaner and then to a sulfur recovery process. The SO_2 concentration will be enriched to 90% by volume by a dimethylamine, DMA, absorber-stripper process. The concentration SO_2 stream is reduced to sulfur by the Asarco process using natural gas as the fuel.

Performance

A temperature-enthalpy diagram for the atmospheric pressure boiler is shown in Figure 33. The theoretical gas temperature, the fluidized bed temperature, and the cold-side fluid temperatures are shown for the full load conditions. This plot graphically describes the allocation of boiler function and illustrates the heat transfer situation in each of the boiler components.

Boiler Performance: The losses for the atmospheric pressure fluidized bed boiler are as follows:

Losses	Percent
Dry gas loss (stack temp -- 275°F)	4.28
Loss due to hydrogen and moisture in coal	5.05
Loss due to moisture in air	0.10
Radiation loss	0.18
Incomplete combustion	1.0 - 2.39
Unaccounted for and manufacturer's margin	1.50
TOTAL	12.49-13.88

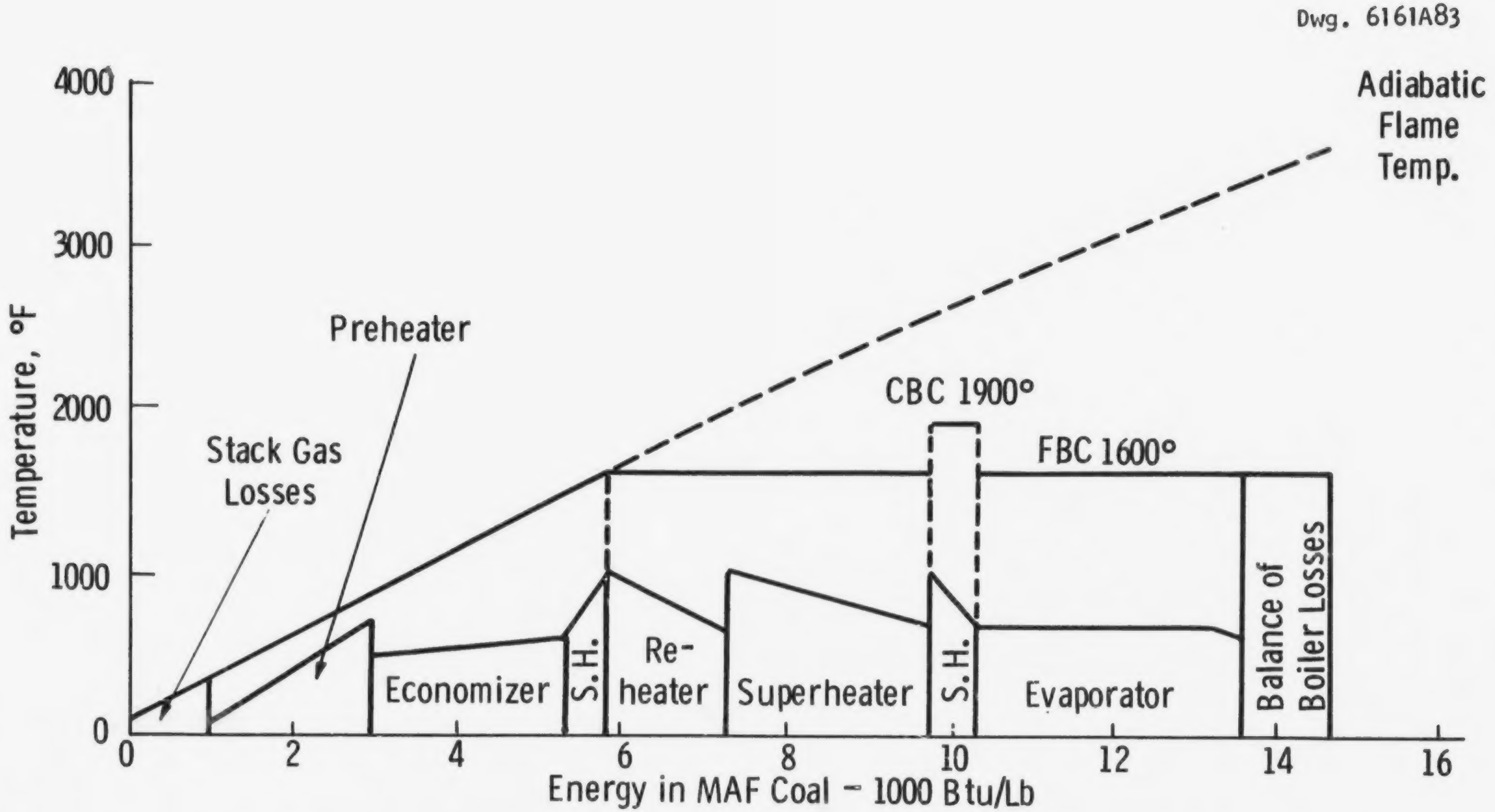


Fig. 33 — Temperature-energy diagram for the atmospheric utility boiler design

Part-Load Performance: A maximum primary bed temperature of 1600°F was chosen on the basis of ash characteristics and sulfur recovery considerations. A lower limit of 1300°F for continuous operation was chosen on the basis of sulfur recovery and combustion efficiency considerations. At part load, the gas-side heat transfer coefficient is nearly constant and there is only a small reduction in steam-side coefficient due to Reynolds number effect. Therefore, the heat transferred from the beds is primarily a function of the bed temperature. Because of the constraints on bed temperatures discussed above, the turn-down capability of a boiler module is only 35% of boiler flow, which is equivalent to about 40% reduction in plant power. To attain 4:1 turn-down capability for the plant, it is necessary to use four boiler modules which can be shut down individually. This gives the plant load profile shown in Figure 34.

Pressure Losses: The gas-side pressure losses at full load are as follows:

Component	Pressure Loss, in H_2O
Ducts	1.43
Distribution Plate	10.8
Bed	27.5
Convection Bank	0.1
Dust Collector	3.0
Air Heaters	
Air-Side	3.0
Gas-Side	1.5
TOTAL	47.33

Since the bed pressure loss is predominant and independent of load, the overall gas-side pressure drop will be relatively unchanged with load. The steam-side pressure losses are 545 psi.

Curve 645614-A

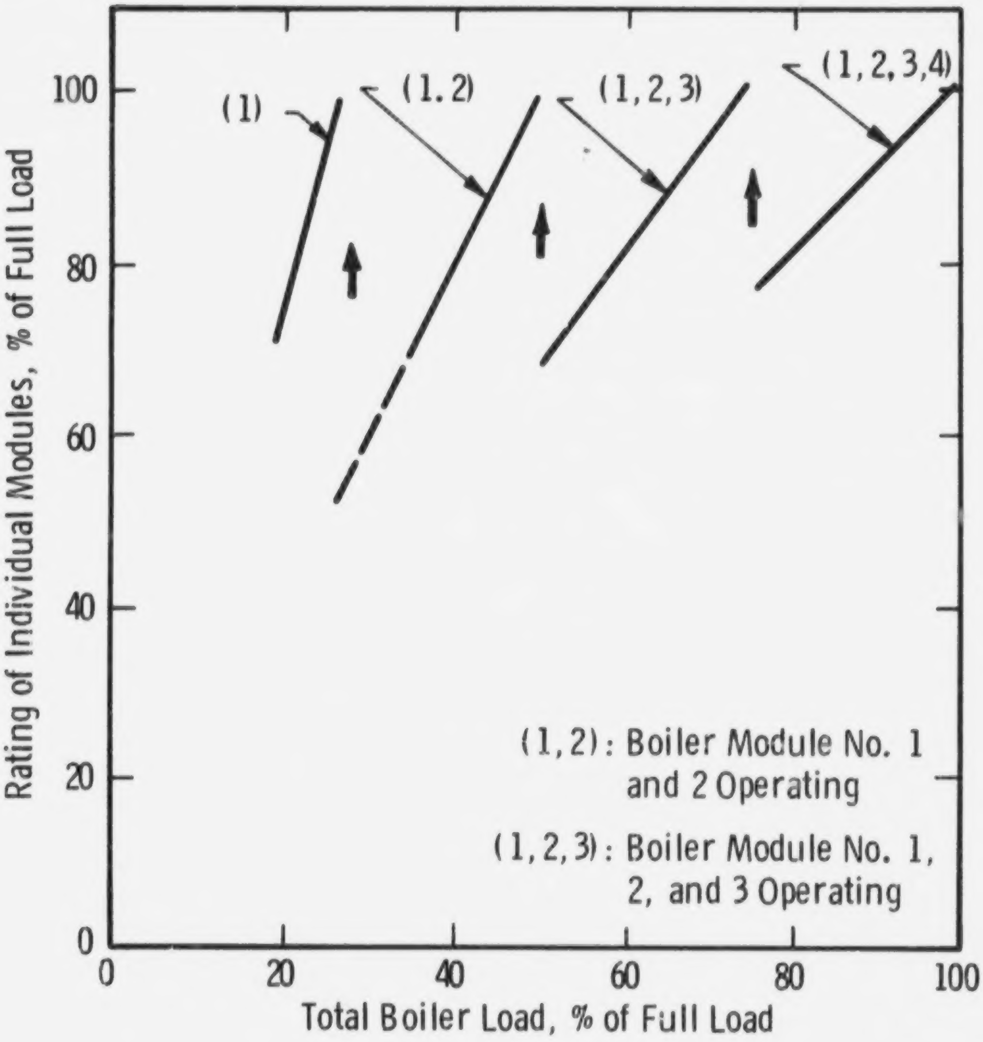


Fig.34 — Boiler load reduction

Pollution Abatement: Projected emissions from the plant are summarized in Table 21.

The sulfur loss in the generator is by the carrier gas for the spent and regenerated stone. The expected sulfur recovery efficiency for the DMA process is 98 to 99%. This process consumes soda ash and dilute sulfuric acid. Vented gas from the DMA scrubber should contain 450 ppm SO_2. The Asarco process is expected to recover approximately 92% of the sulfur fed to it. Adding a third Claus reactor to the two planned should improve the performance. The overall sulfur recovery efficiency for the regenerator-sulfur recovery plant should be around 85%.

Sulfur recovery as sulfuric acid was also considered. Emissions from an acid plant would contain 500 ppm or less SO_2, corresponding to sulfur recovery efficiency in excess of 99%. The overall plant sulfur recovery should be approximately 95%.

Cost estimates for the various components of this regeneration system were obtained from the following sources. Detailed design information is given in Volume III.

- Solids feed system: Westinghouse, Petrocarb, and Foster Wheeler
- Sulfur plant: Allied Chemical Corporation
- Process vessels: Westinghouse.

Plant Performance: The full load heat rate for the site chosen is 9440 Btu/kWh. This corresponds to a back pressure of 1-1/2 in. Hg and a combustion efficiency of 86.1%.

Economics

Capital and energy costs were prepared for pressurized and atmospheric pressure fluidized bed boiler power plants burning high-sulfur coal based on the preliminary designs. Capital and energy costs were also estimated for fluidized bed boiler power plants burning high-

TABLE 21

AIR EMISSIONS SUMMARY

	SULFUR DIOXIDE lb $SO_2/10^6$ Btu	NITROGEN OXIDE lb $NO_2/10^6$ Btu	PARTICULATES lb/10^6 Btu
BOILER PLANT(a) (Boilers Including Coal Drying)	0.7	0.4-0.8	0.02-0.08 (c)
LIMESTONE REGENERATION	---	---	---
SULFUR RECOVERY	0.3-0.5 (b)	---	---
TOTAL	1.0-1.2	0.4-0.8	0.02-0.08

(a) Does not consider fugitive dust.

(b) Includes tail gas sulfur recovery process for Claus plant.

(c) The data indicate that uncontrolled fluidized bed boilers will emit significantly less fine (<10μm) material: ~10wt% vs 30 wt% for conventional plants. Thus, for a 8.5% ash coal, a conventional plant would emit ∿ 40 lb particulates <10μm/ton coal and a FBB is projected to emit ∿ 30 lb ash and stone particulates <10μm/ton coal, without any particulate control.

sulfur oil. Costs are projected for plants with once-through limestone/dolomite and with stone regeneration and sulfur recovery. These costs are compared with the cost for conventional coal- and oil-fired plants with stack gas cleaning.

Assumptions common to all plants are:

- Northeast site
- January 1970 costs
- Begin construction July 1971
- Supplementary cooling not included
- Contingency of 6%
- Escalation at 7-1/2%
- Interest during construction at 7-1/2%
- 70% capacity factor
- 15% fixed level charge
- No credit taken for sulfur recovery
- 45¢/10^6 Btu high-sulfur coal (∿ 4% sulfur)
- 45¢/10^6 Btu high-sulfur oil (∿ 3% sulfur)
- $2/ton limestone or dolomite.

The heat rates for each coal-fired plant are:

Conventional	9230 Btu/kWh
Atmospheric pressure fluidized bed boiler	9550 Btu/kWh
Pressurized fluidized bed boiler combined cycle	8967 Btu/kWh

(Heat rates are for 3 in. Hg turbine back pressure to allow for a cooling tower.)

Capital costs for coal-fired plants are summarized in Table 22. These costs are based on data from Westinghouse, Foster Wheeler, United Engineers and Constructors, and equipment vendor quotes. Air pollution control costs, which are included with the boiler plant equipment cost, are summarized in Table 23. The cost of the pressurized plant is 18 to 21% less than a conventional plant, while the cost of the atmospheric pressure plant is 7 to 12% less. Capital cost as a function of plant

TABLE 22

COAL-FIRED POWER PLANT COST BREAKDOWN
635 MW Plant
(Sulfur Removal Process(es) Designated Under Concept)

	Conventional p.f. Boiler(a) $/kW	Atmospheric-Pressure Fluid Bed Boiler(b) $/kW		Pressurized Fluid Bed Boiler Combined Cycle(c) $/kW	
	Once-Through	Regenerative	Once-Through	Regenerative	Once-Through
Land & Land Rights	1.13	1.13	1.13	1.13	1.13
Structures & Improvements	27.28	25.80	24.80	19.57	18.52
Gasification Plant Equipment	--	--	--	--	--
Boiler Plant Equipment	82.23	71.79	60.80	60.36	52.68
Gas Turbine-Generator Equipment	--	--	--	14.80	14.80
Steam Turbine-Generator Plant Equipment	55.76	54.96	54.96	44.14	44.14
Electric Plant Equipment	14.99	14.99	14.99	15.91	15.91
Misc. Plant Equipment	4.21	4.21	4.21	3.56	3.56
Undistributed Costs(d)	30.01	29.20	29.20	28.35	28.35
Other Plant Costs(e)	2.91	2.91	2.91	2.91	2.91
Sub Total	218.52	204.99	193.00	190.73	182.00
Normal Contingency	13.11	12.30	11.58	11.44	10.92
Sub Total	231.63	217.29	204.58	202.17	192.92
Escalation	52.12	48.08	45.26	37.60	36.17
Sub Total	283.75	265.37	249.84	239.77	229.09
Interest During Construction	47.88	41.80	39.35	31.30	30.07
General Items & Engineering	5.5	5.5	5.5	5.5	5.5
TOTAL CAPITAL COST	337.13	312.67	294.69	276.57	264.66

CONSTRUCTION TIME

Type of Plant	No. of Years
Conventional Plant	4.5(f)
Atmospheric Pressure Fluid Bed Boiler Plant	4.2(g)
Pressurized Fluid Bed Boiler Plant	3.5(h)
Fluidized Bed Gasification	3.5

(a) Conventional plant cost data provided by United Engineers and Constructors. Plant includes throw-away wet scrubbing system and NO_x control.

(b) Cost estimate prepared by Westinghouse on component data supplied by Westinghouse, Foster Wheeler, and United Engineers and Constructors. Plant includes sorbent regeneration and sulfur recovery system.

(c) Cost estimate prepared by United Engineers and Constructors based on component data supplied by Westinghouse, Foster Wheeler, and United Engineers and Constructors. Plant includes sorbent regeneration and sulfur recovery.

(d) Engineering and construction management and supervision, temporary facilities, construction services, etc.

(e) Operator training, spare parts, etc.

(f) Source -- United Engineers and Constructors.

(g) Construction time reduction for boiler projected by Foster Wheeler assumed for total plant.

(h) Construction schedule prepared by United Engineers and Constructors.

TABLE 23

AIR POLLUTION CONTROL EQUIPMENT COST

	Conventional p.f. Boiler $/kW	Atmospheric Pressure Fluid Bed Boiler $/kW		Pressurized Fluid Bed Boiler $/kW	
		Regenerative	Once-Through	Regenerative	Once-Through
SO_2 Removal	20(a)	(b)	(b)	(b)	(b)
Sulfur Recovery	--	15.2	--	12.68	--
Particulate Control(c)	(a)	5.0	5.0	(d)	(d)
NO_x Minimization	3.50	(e)	(e)	--	--
	23.50	20.2	5.0	12.68	--

(a) The wet scrubber is assumed to achieve adequate particulate removal. Recent cost data(8) indicate the cost for SO_2 and particulate control by wet scrubbing for a new plant can be as high as $40/kW.

(b) Sulfur dioxide is removed in the boiler.

(c) Ash handling cost is not included.

(d) Particulate removal is required for gas turbine operation. This cost is not attributed to pollution control.

(e) Additional NO_x control may be required to meet proposed regulations.

capacity for a conventional coal-fired plant and fluidized bed boiler plants with sulfur recovery is shown in Figure 35 . Capital costs projected for oil-fired plants are summarized in Table 24. The cost estimate for the atmospheric-pressure fluidized bed boiler plant is only 2% less than a conventional plant, while the estimate for the pressurized combined cycle plant is 14% less.

Energy costs for coal- and oil-fired plants are summarized in Tables 25 and 26 . Energy cost reductions for pressurized fluidized bed combustion combined cycle coal-fired plants with sulfur recovery may be ∿10% or 1-1/4 to 1-1/2 mills/kW-hr below conventional plant energy costs. The reduction in energy costs for atmospheric pressure fluidized bed combustion with sulfur recovery is estimated to be ∿2%. Energy cost reductions for pressurized fluidized bed combustion combined cycle oil-fired plants with sulfur recovery may be ∿7% below conventional plant energy costs. Atmospheric pressure fluidized bed oil gasification with sulfur recovery does not show energy cost reductions over new conventional plants if the \$20/kW capital cost for SO_2 flue gas cleaning systems is achieved.

Evaluation

Atmospheric and pressurized fluidized bed combustion power systems were evaluated on the basis of:

- Design characteristics
- Effectiveness for pollution abatement
- Effectiveness for fuel utilization
- Economy of power generation
- Status of technology
- Development requirements.

The fluidized bed combustion systems are compared with each other and with a conventional p.f. coal-fired plant with stack gas cleaning.

Comparison

In making comparisons of technology, the state of development and the economics must be considered, and a balanced assessment

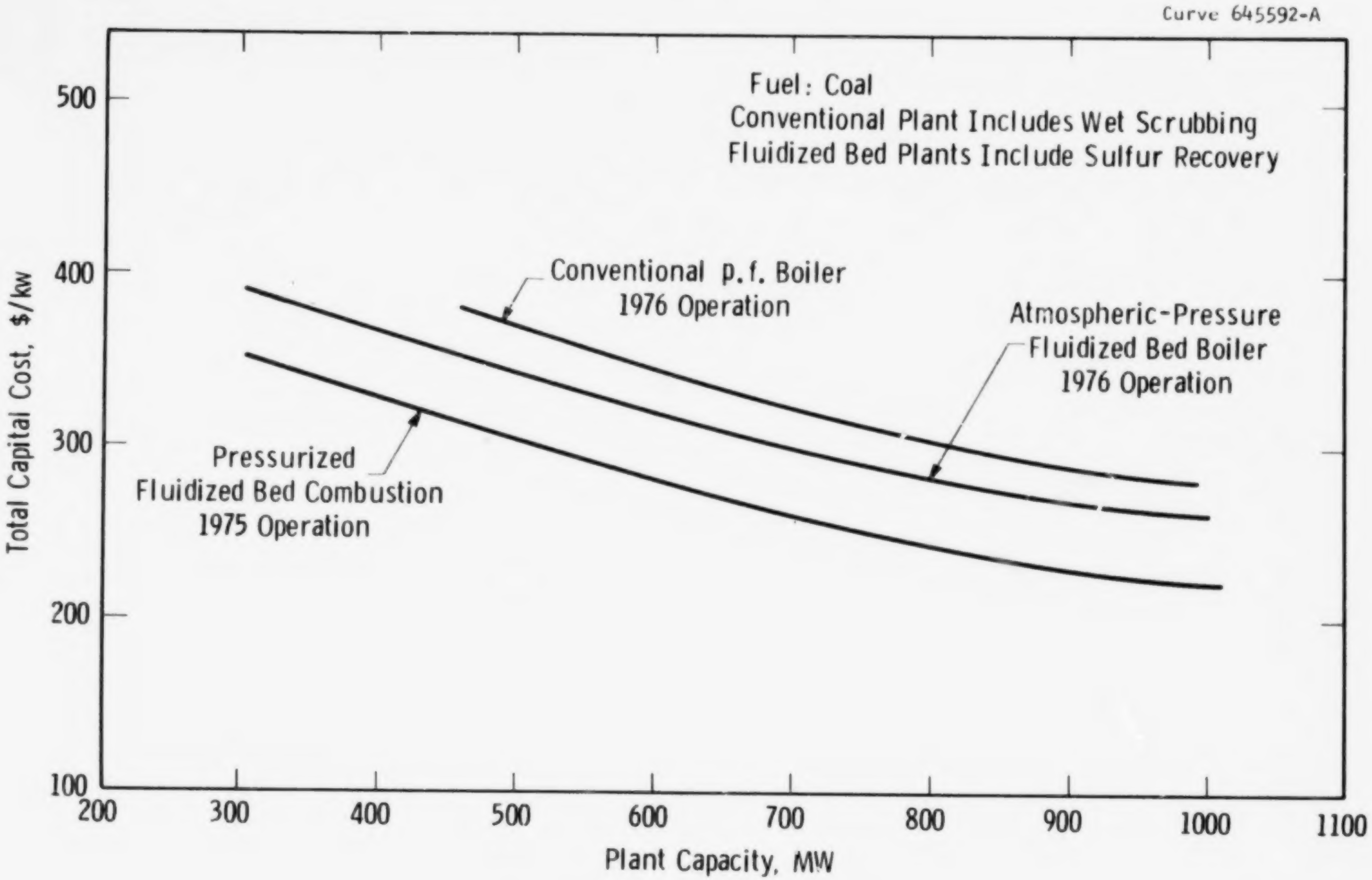


Fig. 35 - New Plant Cost vs. Capacity

TABLE 24

OIL-FIRED POWER PLANT COST BREAKDOWN
635 MW Plant

	Conventional[(a)] $/kW	Atmospheric Pressure Fluid Bed Combustion $/kW Regenerative	Pressurized Fluid Bed Combustion $/kW Regenerative
Land & Land Rights	1.13	1.13	1.13
Structures & Improvements	24.95	25.80[(b)]	19.57[(b)]
Boiler Plant Equipment	47.31	51.76	40.89
Sulfur Removal Equipment	20.00[(c)]	14.10	12.68
Gas Turbine-Generator Equipment	--	--	14.80
Steam Turbine-Generator Equipment	55.76	54.96	44.14
Electric Plant Equipment	14.40	14.40	15.30[(d)]
Misc. Plant Equipment	4.08	4.08	3.45[(d)]
Undistributed Costs	28.55	27.80[(d)]	27.00[(d)]
Other Plant Costs	2.91	2.91	2.91
Sub Total	199.09	196.94	181.87
Normal Contingency	11.95	11.82	10.91
Sub Total	211.04	208.76	192.78
Escalation	47.78	46.19	36.15
Sub Total	258.52	254.95	228.93
Interest During Construction	43.63	40.14	30.05
General Items of Engineering	5.5	5.5	5.5
TOTAL CAPITAL COST	307.65	300.60	264.48

(a) Assumes stack gas scrubbing system, no particulate control beyond scrubber, no additional stack height over alternates. No by-pass around the scrubber system is provided.

(b) Same as coal-fired plant.

(c) Once-through throw-away system.

(d) Estimated by assuming same percent reduction for oil-fired plant as was assumed with coal-fired plant over conventional coal-fired plant.

TABLE 25

ENERGY GENERATION COSTS FOR COAL-FIRED POWER PLANTS(a)

	Conventional p.f. Boiler	Atmospheric-Pressure Fluidized Bed Boiler		Pressurized Fluidized Bed Boiler Combined Cycle	
Sulfur Removal System	Once-Through	Regenerative	Once-Through	Regenerative	Once-Through
Fixed Charges	8.25	7.61	7.20	6.75	6.44
Fuel	4.11	4.60(b)	4.30	4.35(b)	4.04
Dolomite or Limestone	0.05	0.05	0.29	0.12	0.52
Operating and Maintenance	0.99(c)	0.86	0.67	0.90	0.71
TOTAL, mills/kWh	13.40	13.12	12.46	12.12	11.71

(a) Basis:
- 635 MW plant capacity
- High-sulfur coal - 4.3%
- 70% load factor
- Begin construction July 1971
- Costs in mills/kWh

(b) Includes fuel for regeneration process.

(c) O&M for wet scrubbing was estimated to be 0.32 mills/kWh. Recent data indicate that this is low, and the cost may approach 1 mill/kWh.

TABLE 26

ENERGY GENERATION COSTS FOR OIL-FIRED POWER PLANTS
635 MW PLANT

Sulfur Removal System	Conventional Boiler (Once-Through)	Atmospheric Pressure Fluidized Bed Boiler (Regenerative)	Pressurized Fluidized Bed Boiler Combined Cycle (Regenerative)
Fixed Charges	7.52	7.35	6.47
Fuel	4.11	4.60	4.35
Dolomite or Limestone	0.05	0.05	0.12
Operating and Maintenance	0.91	0.78	0.82
TOTAL. mills/kWh	12.59	12.78	11.76

rendered. Demonstration installations of wet scrubbers are well underway: 70 to 90% removal of SO_2 may be achieved; some operating problems -- corrosion and deposition -- must be solved. Costs of new scrubber installations are estimated to be \$20 to \$25/kilowatt. This cost may be as high as \$40 to \$50/kilowatt.(8) Combustion modification techniques on large conventional boilers have been under investigation. It appears that NO_x emissions may be reduced appreciably by two-stage combustion, low excess air, or flue gas recycle.

Atmospheric fluidized bed combustion is still in a developmental stage. Demonstrated SO_2 removal is 80 to 90%; NO_x reduction may not be adequate to meet emission standards. The technology of sorbent regeneration and sulfur recovery is not sufficiently developed for accurate systems design and economic evaluation. With reasonably optimistic assumptions, energy costs from atmospheric fluidized bed boiler power plants are estimated to be 2 to 3% less than from conventional plants equipped with wet scrubbers. This cost advantage might well disappear as further technical data are developed on the atmospheric system.

Pressurized fluidized bed combustion is also in the development stage. Demonstrated SO_2 and NO_x reductions are adequate to meet emission standards. Energy costs are projected to be 8 to 9% -- and potentially 24% -- less than conventional power plants. There is thus a much larger economic margin for solving technological problems.

System evaluation and experimental test results indicate that the pressurized system is more attractive for pollution abatement and in economy of operation. A summary of the plant comparisons is presented in Table 27. The commercialization of either the atmospheric or the pressurized system would require 9 to 11 years and \$65 to 75 x 10^6, primarily because the construction of the demonstration plant dominates the time and cost estimates.

TABLE 27

SUMMARY OF PLANT COMPARISONS[a]

	Conventional With Scrubbing System	Atm. Press. FBB		Pressurized FBB	
		Regenerative	Once-Through	Regenerative	Once-Through
COST					
Installed Capital Cost, \$/kW	337	313	295	277	264
Energy Cost, mills/kWh w/o sulfur credit	13.40	13.12	12.46	12.12	11.71
ENVIRONMENTAL FACTORS					
Plant Heat Rate (exclusive of sulfur recovery or removal systems) Btu/kWh	9230	9550		8967	
SO_2, ($lb/10^6$ Btu)	1.5	0.70		0.70	
NO_x, (lb $NO_2/10^6$ Btu)	1.2-1.4 w/o recir.	0.4-0.8		0.1-0.2	
Particulate, ($lb/10^6$ Btu)	0.05-0.15	0.05		0.05-0.15	
POTENTIAL FOR ADVANCED CONCEPTS					
Cost	No reduction projected	290		240	
Cost	No reduction projected	11.90		10.30	
Efficiency	No increase projected	40%		47%	
FLUIDIZED BED BOILER SYSTEMS					
Relative Advantages (Technical)		Less stringent particulate removal More exp. data on operation		Coal feeding NO_x removal Control Higher efficiency Reduced size, reduced heat transfer surface, greater potential, reduced construction time	
Technical Problem Areas		Coal feeding, NO_x emission, control, SO_2 removal		Deep beds, gas turbine blade erosion, SO_2 removal, solids handling	

[a] Basis: 600 MW Capacity
4.3% Coal

The number of common technical problems remaining in atmospheric and pressurized systems appears very small. The order of magnitude difference in pressure, in mass flow per unit of bed area, and in bed depth make it difficult to transfer technical information and design procedures.

In conclusion, the conventional power plant with combustion modification and wet scrubbers is the most highly developed technology. Pressurized fluidized bed combustion is the most promising fluidized bed combustion technology from the point of view of effective pollution abatement, efficient fuel utilization, and economical power generation. Atmospheric fluidized bed combustion may be better than conventional systems, but further development is required.

Potential

Potential energy cost reductions for fluidized bed power generation systems are projected as the result of:

- Modification of the present design concepts
- Advanced boiler-regeneration-sulfur recovery designs and power cycles
- Utilization of low grade fuels.

Modification of Present Concepts:

Potential simplifications and improvements in the present pressurized fluidized bed boiler combined cycle plant may reduce the $276/kW capital cost by $20/kW.(9) This corresponds to an energy cost reduction of 4% in the present pressurized plant design. If the gas turbine temperature is increased by burning above the bed or lowering projected heat losses between the boiler and the gas turbine, the plant heat rate would increase 1 to 2%. This would result in additional energy cost reduction. The potential energy cost reduction with the pressurized combined cycle plant with sulfur recovery may be 14% less than a conventional plant with wet scrubbing. Modification in the present atmospheric pressure boiler plant design concept does not appear to result in significant cost reductions.

Advanced Concepts: Advanced designs have the potential for reducing capital costs and reducing the plant heat rate over the present design concepts. Three areas have been considered: boiler design, regeneration-sulfur recovery processes, and power cycle conditions.

- Advanced boiler design concepts have been conceived which have potential advantages in maintaining uniform bed temperature, in feeding reactants to the bed, in separating ash, and in power plant control.
- Regeneration-sulfur recovery processes have been assessed in order to develop a process with reduced capital cost and improved operability.
- The power cycle operating conditions can be advanced to improve the plant heat rate -- increased gas turbine temperature and increased steam temperature and pressure.

In the high-pressure combined cycle system the bed temperature, rather than the gas turbine inlet temperature, is limiting. If a way is found to decrease the temperature difference between the bed and the gas turbine, or if a supply of gaseous fuel is produced* for heating the exhaust products from the beds to the current limiting level for the gas turbine, i.e., 1800-1900°F, the plant heat rate would decrease 2 to 3% and the plant capacity would increase 5 to 8%. The effect on specific plant cost would be somewhat less than the capacity change. Gas turbine temperatures of 2500°F are projected for 10 to 15 years from now, so the potential for growth in this area is substantial. No significant improvements are expected in gas turbine aerodynamic efficiencies in the foreseeable future. However, there is a definite trend in gas turbine design toward higher mass flows on an area basis. This will bring about further reduction in specific plant cost. Reduced corrosion in fluidized bed boilers could result in increasing steam temperatures to 1200°F or higher. Both the plant capacity and the plant heat rate would change about 4% per 100°F increase. Near improvements in gas turbine and steam turbine utilization could result in heat rate improvements on the order of 10% and in specific plant cost reduction on the order of 10 to 15%. Longer term advances in gas and steam turbine temperatures and pressure would bring about further improvements.

---

*This may be achieved by gasifying the carbon carry-over from the primary beds.

The potential energy cost reductions for the atmospheric pressure and pressurized fluidized bed boiler plants based on successful development of the advanced concepts are summarized in Table 28. The energy costs for the atmospheric pressure and pressurized systems represent reductions of 10% and 22% respectively over a conventional plant with stack gas cleaning.

TABLE 28

ADVANCED FLUIDIZED BED COMBUSTION POWER PLANT COSTS WITH SULFUR RECOVERY(a)

	Atmospheric Pressure Plant	Pressurized Plant
Capital Cost, $/kW	290	240
Heat Rate, Btu/kWh	8300	7600
Energy Cost, mills/kWh	11.90	10.30

(a) Basis: 600 MW

Fuel Utilization: Fluidized bed combustion boilers offer a means of burning low-grade fuels which cannot be effectively burned in conventional boilers. Two advantages can be realized: effective utilization of fuel resources, and reduction in energy cost as the result of low-cost fuel supplies.

ASSESSMENT OF ATMOSPHERIC PRESSURE FLUIDIZED BED OIL GASIFICATION

Specifications and design concepts were established for atmospheric pressure fluidized bed oil gasification systems for retrofit on existing utility boilers and for new plants. Conceptual designs, performance, and costs were prepared and compared with conventional alternatives -- low-sulfur oil, desulfurized oil, and stack gas cleaning.

SPECIFICATIONS

Process specifications of importance in oil gasification/desulfurization are listed on the following page. The four factors which are listed as functional variables (geographic location, fuel oil, limestone, and sulfur removal) are determined by the market outlook, by residual oil and limestone availability, and by the expected SO_2 emission standards, respectively.

The design variables listed on page 140 refer to the broad design factors which will determine the feasibility of preliminary design concepts. The design considered may be that of a new boiler or a boiler retrofit, and the three factors -- boiler size, boiler load factor, and boiler turn-down ratio -- are important in determining the design for either a new system or a retrofit system. In the retrofit case, the type of boiler being retrofit is important because coal- and oil-fired boilers differ in retrofit characteristics. The location of the gasification system relative to the boiler structure (internal to the boiler or external to the boiler) and the configuration of the gasification system (singular or modular) are basic considerations in both new and retrofit designs. The other important design variable considered in the preliminary design is the mode of operation (regenerative or once-through).

SPECIFICATIONS

FUNCTIONAL VARIABLES:

- Geographic Location
- Fuel Oil
- Limestone
- Sulfur Removal
- Boiler Size
- Load Factor
- Turn-down Ratio

DESIGN VARIABLES:

- New Boiler Design
- Retrofit Design - (Coal- or Oil-Fired)
- Gasification System Location
  - Internal to Boiler
  - External to Boiler
- Gasification System Operational Mode
  - Regenerative or Once-Through
- Gasification System Configuration
  - Unit Design or Modular, etc.

TEMPERATURE CONTROL:

- Gasifier Temperature Control
  - Stack Gas Recycle
  - Water Injection
  - Steam Injection
  - Heat Transfer Surface
  - Air/Fuel Ratio
- Regenerator Temperature Control
  - Stone Circulation Rate
  - Addition of Make-up Stone
  - Heat Transfer Surface
- Sulfate Generator Temperature Control
  - Excess Air Circulation
  - Heat Transfer Surface

OPERATING VARIABLES:

- Fluidization Velocity
- Particle Sizes
- Air/Fuel Ratio
- Limestone Make-up Rate
- Limestone Utilization
- Bed Depth
- Bed Temperature - Gasifier and Regenerator

The operating variables listed were found to be important in the Esso, England, batch studies. In addition, the schemes proposed to control the temperatures of the gasifier, regenerator, and sulfate generator are listed. Possible methods for gasifier temperature control are the recycle of stack gas (presently being used with the Esso, England, continuous pilot unit); water or steam injection; the use of heat transfer surface in the gasifier to preheat boiler water; or possibly reducing the air/fuel ratio to the point of thermal balance. In the regenerative operation, the regenerator temperature might be controlled by regulating the time circulation rate (as is presently being done with the Esso, England, continuous pilot unit), by adding fresh make-up limestone to the regenerator, or by including heat transfer surface in the regenerator vessel. Methods proposed for control of the sulfate generator in the once-through operation are the circulation of excess air through the sulfate generator or the inclusion of heat transfer surface in the vessel.

The specifications assumed for the conceptual design are presented on the following page. The process specifications include a geographic location for the commercial development of the atmospheric pressure residual oil gasification/desulfurization process in the Eastern United States, based on market predictions. Preliminary designs are based on a residual oil containing 3 wt % sulfur with a low heating value of 17,700 Btu/lb, a limestone with the composition of the U.K. limestone investigated by Esso, England, and a sulfur removal efficiency of 90 to 95% to meet present and future pollution standards.

For the purpose of cost estimates, a boiler capacity of 600 MW and load factors of 40% and 80% were considered. In general, capacities of 100 MW and greater are of interest in the preliminary designs. A turn-down ratio of 4:1 was of interest with both new and retrofit designs.

The operating variables are specified according to the Esso, England, batch data. The gasifier temperature of 1600°F, for both regenerative and once-through operations, is chosen from the Esso, England, data as optimum from the standpoint of sulfur removal. From

CONCEPTUAL DESIGN SPECIFICATIONS

PROCESS SPECIFICATIONS

Geographic Location: Eastern U.S.

Fuel Oil: 3 wt % Sulfur; LHV = 17,700 Btu/lb

Limestone: U.K. Limestone

Sulfur Removal: 90-95%

DESIGN VARIABLES

Boiler Size: 600 MW

Load Factor: 40%, 80%

Turn-down: 4/1

OPERATING VARIABLES

	Regenerative	Once-Through
Gasifier Temperature	1600°F	1600°F
Regenerator (Sulfate Generator) Temperature	1900°F	1500°F
Stone Make-up Rate	1 mole CaO/mole sulfur	3 moles CaO/mole sulfur
Air/Fuel Ratio	20% of stoichiometric	20% of stoichiometric
Limestone Utilization	∿ 5 wt % sulfur in bed	∿ 19 wt % sulfur in bed
Fluidization Velocity	8 ft/sec	8 ft sec
Particle Sizes (Avg.)	∿ 2000 μ	∿ 1000 μ
Gasifier Bed Depth (Static)	2.5-3.5 ft	3.5-4.0 ft

PROJECTED PERFORMANCE

	Regenerative	Once-Through
Sulfur Removal	90-95%	90-95%
Thermal Efficiency	90-98	90-98
Elutriation	∿ 2-5% of bed/hr	∿ 2-5% of bed/hr
Vanadium Retention	∿ 100%	∿ 100%
Sodium Retention	∿ 20%	∿ 20%

the standpoint of lime regeneration, the data indicate 1900°F for the regenerator temperature. A temperature of 1500°F was chosen for the sulfate generator based on chemical equilibrium to give an SO_2 partial pressure of less than 0.01 atmospheres coming off the sulfate generator and a high conversion of calcium sulfide to calcium sulfate, though the kinetics of the reaction have not been investigated. The Esso, England, cyclic batch tests indicate that a limestone make-up rate of 1 mole CaO per mole of sulfur fed is specific for 90 to 95% sulfur removal in the regenerative operation with 5 wt % sulfur on the gasifier lime, an average stone diameter of 2000 μ, a velocity of 8 ft/sec, and a gasifier bed depth of 2.5 to 3.5 ft. A feed rate of 3 moles of CaO per mole of sulfur fed is specified from the fresh bed data for once-through operation to give 90 to 95% sulfur removal, with 19 wt % sulfur on the gasifier lime, an average stone diameter of 1000 μ, a velocity of 8 ft/sec in the gasifier, and a gasifier bed depth of 3.5 to 4.0 feet. An air:fuel ratio of 20% of stoichiometric is specified from the Esso data in order to assure reasonable carbon deposition rates in the regenerative and once-through operations.

GASIFICATION/DESULFURIZATION CONCEPTS

Fundamentally, oil gasification/desulfurization consists of a complex cracking-partial combustion phenomenon in a fluidized bed (the gasifier) of lime. H_2S evolved during this complex operation is simultaneously absorbed by the lime bed to yield a clean fuel gas and a sulfided lime at a control temperature of 1600°F. The hot, low-sulfur, fuel gas from the gasifier is transported directly to the boiler where combustion is completed. This is schematically represented in Figure 36.

Two possible modes for the gasification/desulfurization operation are the regenerative mode and the once-through mode. Figure 37 illustrates the major process streams and identifies the basic elements of the two operational modes, without reference to the specific system configuration or specific retrofit concepts. The operating variables and temperature control schemes differ slightly for the two modes.

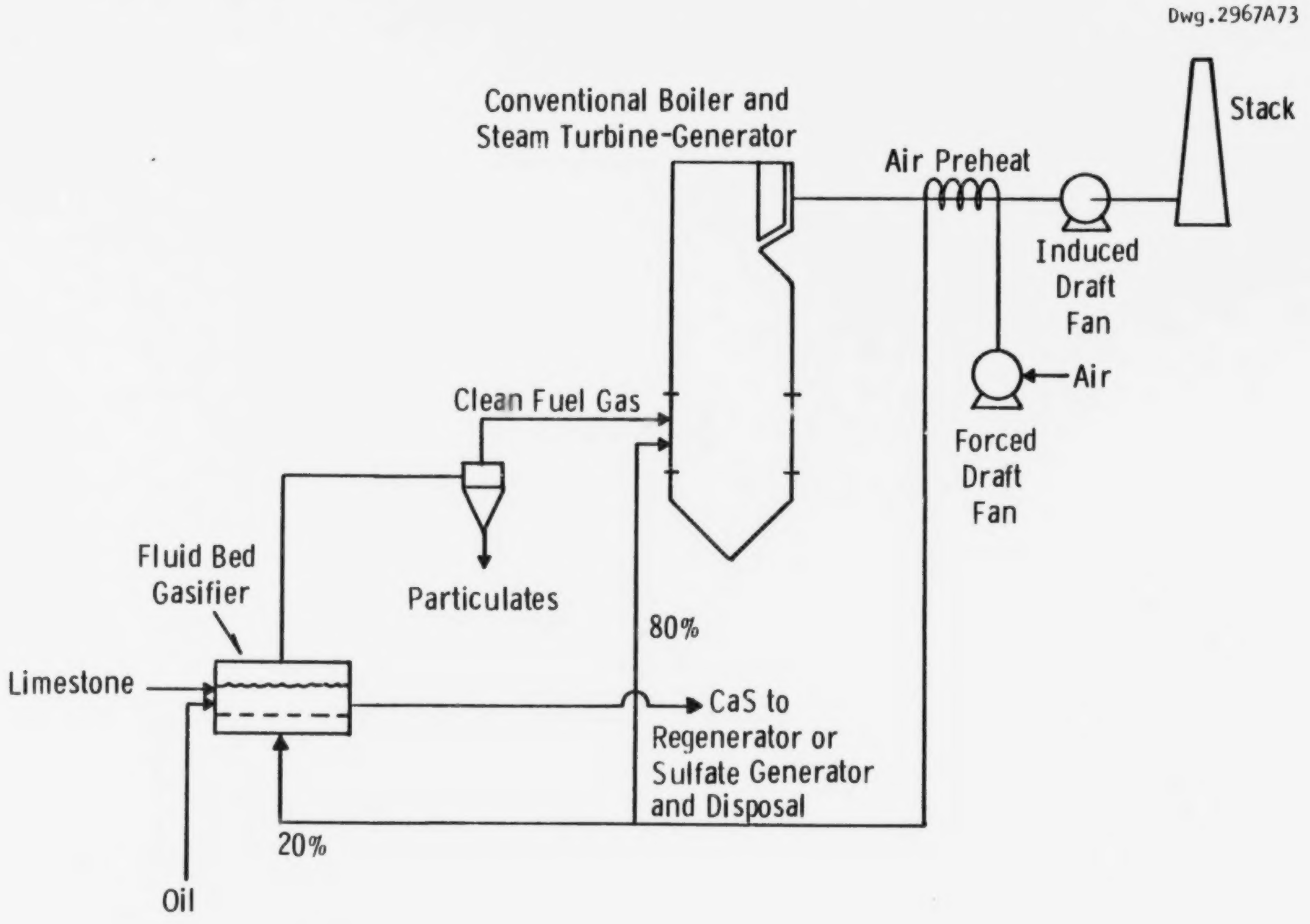
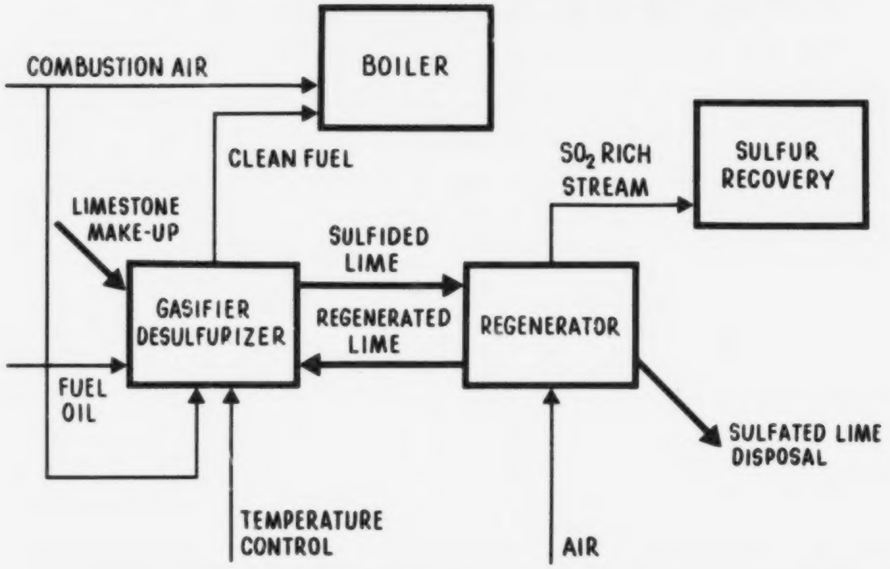
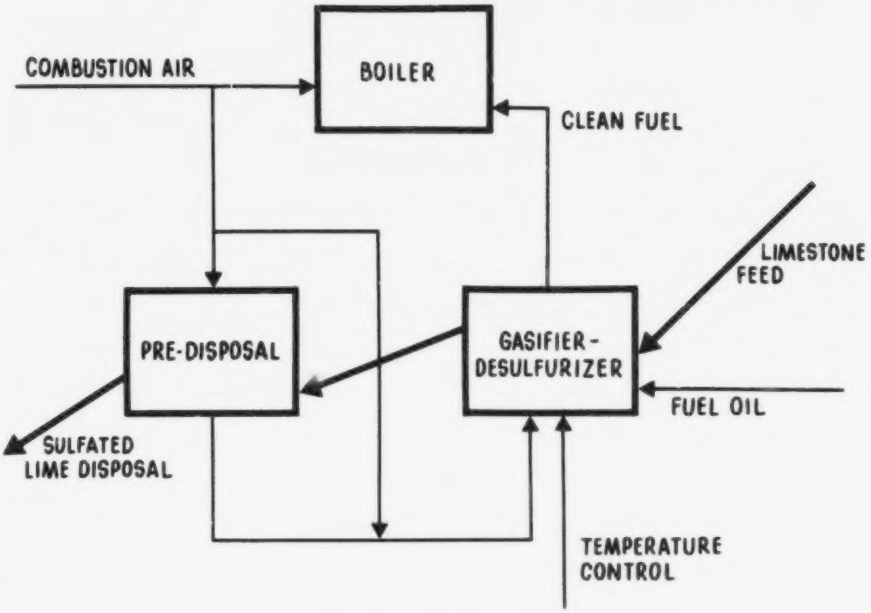


Fig. 36 –Atmospheric fluidized bed oil gasification power plant

REGENERATIVE OPERATION



ONCE-THROUGH OPERATION



[illegible]

The basic elements of the regenerative operation are the gasifier vessel and the regenerator vessel, as shown in Figure 37. In the regenerative operation, residual oil is injected into the gasifier vessel, an air-fluidized bed of lime at 1600°F operated with substoichiometric air (∿ 20% of stoichiometric). The processes of cracking, partial combustion, and H_2S absorption by the lime, yield a hot, low-sulfur, fuel gas and a sulfided lime. The fuel gas is transported to the boiler burners, where combustion is completed, and the sulfided lime is sent to the regenerator. The regenerator is an air-fluidized vessel operated with a slight excess of air at 1900°F. Regeneration takes place by reaction of oxygen with the utilized lime to give an SO_2 rich stream (of about 10 mole % SO_2) and a regenerated lime with a decreased activity compared to that of fresh lime. The SO_2 stream is transported to a sulfur recovery system, and the regenerated lime is returned to the gasifier along with a nearly stoichiometric amount of fresh make-up limestone.

A variety of temperature control schemes may be useful in controlling the temperature of the gasifier and the regenerator. The temperature control scheme used in the gasifier must conserve the energy of the fuel in a form usable in the boiler. For this reason water injection, steam injection, and stack gas recycle are considered for temperature control of the gasifier by the storage of sensible heat. The use of heat transfer surface in the gasifier to preheat boiler water is also an attractive possibility. A fifth possibility exists in the air/fuel ratio, which might be lowered to a value low enough (∿ 14% of stoichiometric) that the gasifier is thermally balanced and no further temperature control need be considered.

Because of the high cost of sulfur recovery, temperature control of the regenerator is best accomplished in a way that avoids diluting the SO_2 stream produced by regeneration. For this reason temperature control by heat transfer surface in the regenerator, by the addition of fresh make-up stone to the regenerator, or by controlling the rate of lime circulation between the gasifier and regenerator is investigated.

The important operating variables in the regenerative operation are the air/fuel ratio, the gasifier and regenerator temperatures, the limestone particle size, the gasifier and regenerator fluidization velocities and bed depths, the stone residence times in both the gasifier and regenerator, and the limestone make-up rate. The effects of these variables are interrelated with the temperature control schemes used and the fuel and limestone properties.

An important phenomenon which takes place in the gasifier during the cracking-partial oxidation is the deposition of carbon, or coking, on the gasifier lime. Carbon deposition affects the sulfur removal efficiency, the thermal efficiency of the system, and the overall operation of the gasifier and regenerator when in the regenerative mode. Minimizing the rate of carbon deposition is, then, an important design consideration.

The elements of the once-through operation, shown in Figure 37, are a gasifier vessel and a sulfate generator, or pre-disposal vessel. The operation of the once-through gasifier is the same as that of the regenerative operation gasifier. The sulfate generator operates similarly to the regenerator but at a lower temperature (∿1500°F) so the sulfated lime from the gasifier is converted to calcium sulfate rather than calcium oxide. The calcium sulfate may be disposed of while the gas stream from the sulfate generator is sent to the gasifier. A limestone addition rate of three to four times that used in the regenerative operation is necessary in the once-through operation.

The same five temperature control methods proposed for the regenerative gasifier are considered for the once-through gasifier, while the sulfate generator temperature is controlled by one of two proposed schemes: heat transfer surface or excess air circulation.

The same operating variables are important in the once-through operation as in the regenerative operation, and carbon deposition is again an important factor in determining the sulfur removal efficiency and the overall system operation. However, in the once-through operation, the carbon deposition rate does not affect the system's thermal efficiency because the thermal energy of the deposited carbon is recycled as sensible heat from the sulfate generator back to the gasifier.

DESIGN

Energy and material balances provide basic information with which the feasibility of applying the gasification/desulfurization concept as an add-on to an existing boiler, or as a new plant design feature, may be examined. The feasibility of the retrofit concept is examined in terms of the availability of space in an existing power plant, the modifications necessary to retrofit an existing boiler, and the performance of a modified boiler.

Plant Layout: Figures 38 and 39 show plant layouts for 200 MW regenerative and once-through gasification/desulfurization systems. The plants consist of two gasification modules, each utilizing air from one of the two power plant forced draft fans present in the existing boiler.

Equipment: Gasification/desulfurization equipment necessary for a retrofit boiler is listed below. However, the equipment will vary from one retrofit to another, depending on the type of boiler being retrofit. Both once-through and regenerative modes are considered in the table, and boiler modification is included as a factor in the following equipment list:

PLANT EQUIPMENT

Regenerative

Gasifier Vessel
Regenerator Vessel
Limestone Handling Equip.
Sulfur Recovery Plant
Fans, Compressors
Storage
Particulate Clean-up Equip.
Burners
Boiler Modification

Once-through

Gasifier Vessel
Sulfate Generator Vessel
Limestone Handling Equip.
Fans, Compressors
Storage
Particulate Clean-up Equip.
Burners
Boiler Modification

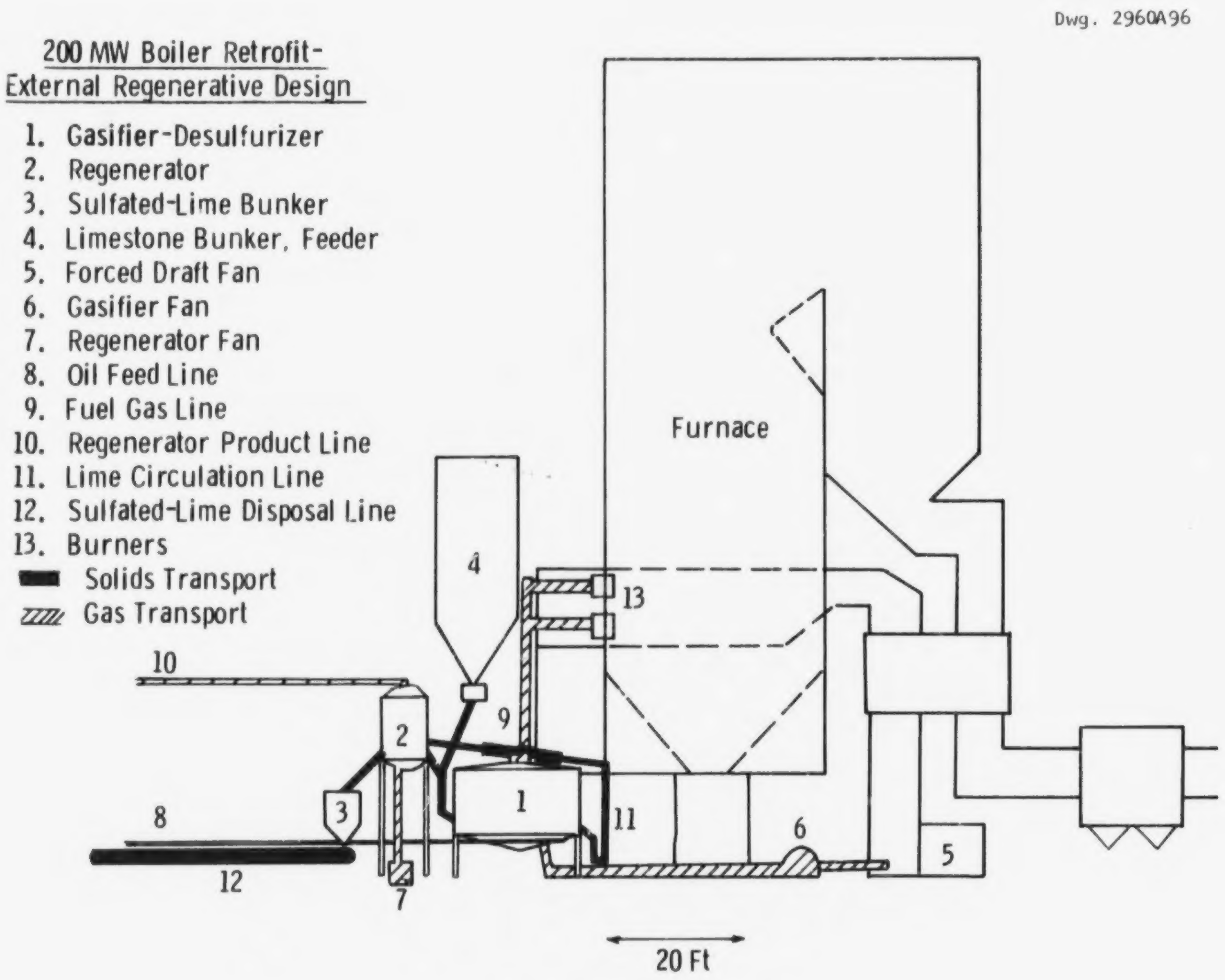

Dwg. 2960A96
200 MW Boiler Retrofit-
External Regenerative Design
1. Gasifier-Desulfurizer
2. Regenerator
3. Sulfated-Lime Bunker
4. Limestone Bunker, Feeder
5. Forced Draft Fan
6. Gasifier Fan
7. Regenerator Fan
8. Oil Feed Line
9. Fuel Gas Line
10. Regenerator Product Line
11. Lime Circulation Line
12. Sulfated-Lime Disposal Line
13. Burners
▬ Solids Transport
▨ Gas Transport
Furnace
1
2
3
4
5
6
7
8
9
10
11
12
13
20 Ft

Fig. 38

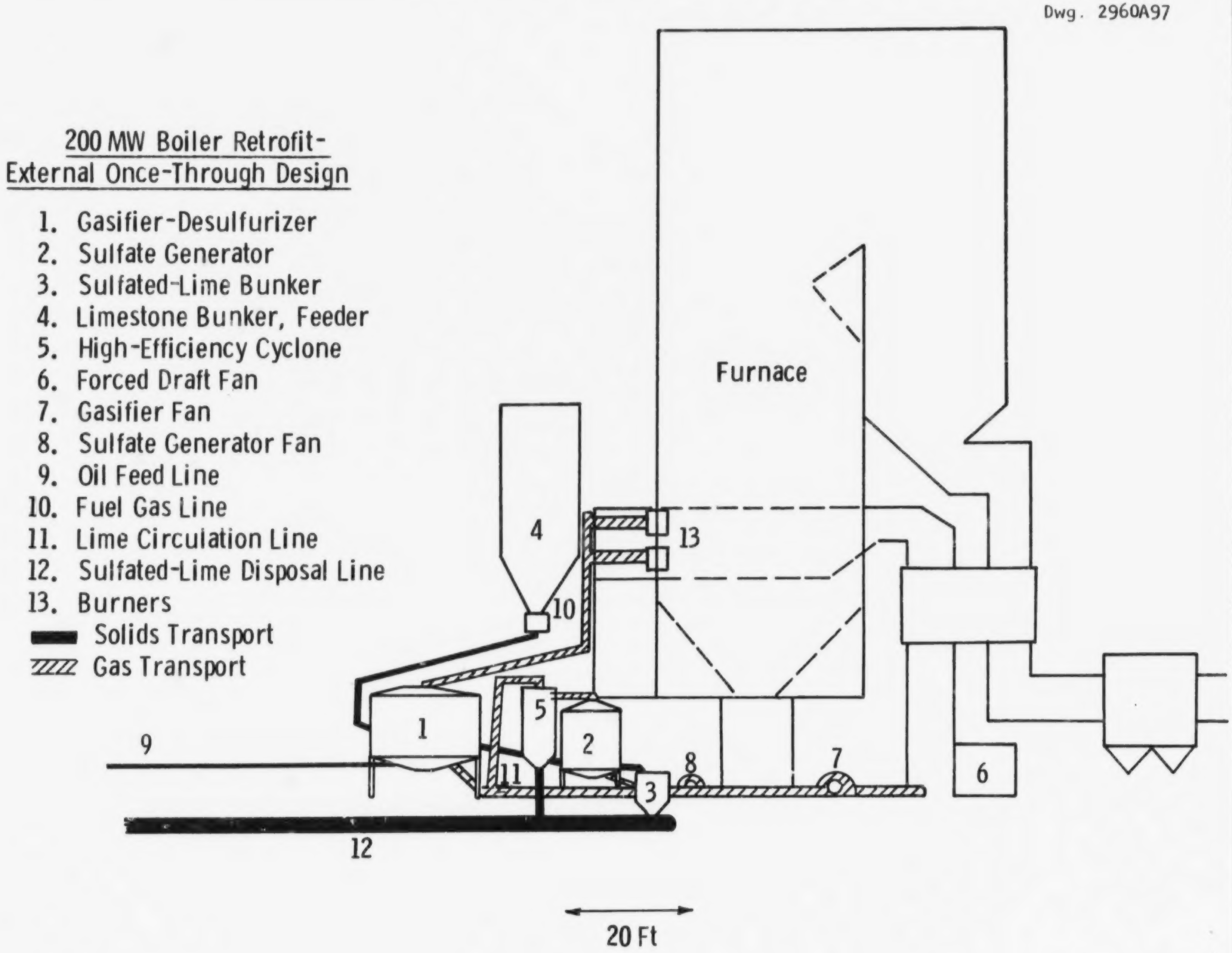

Dwg. 2960A97
200 MW Boiler Retrofit-
External Once-Through Design
1. Gasifier-Desulfurizer
2. Sulfate Generator
3. Sulfated-Lime Bunker
4. Limestone Bunker, Feeder
5. High-Efficiency Cyclone
6. Forced Draft Fan
7. Gasifier Fan
8. Sulfate Generator Fan
9. Oil Feed Line
10. Fuel Gas Line
11. Lime Circulation Line
12. Sulfated-Lime Disposal Line
13. Burners
Solids Transport
Gas Transport
Furnace
1
2
3
4
5
6
7
8
9
10
11
12
13
20 Ft

Fig. 39

Retrofit Concepts: The feasibility of converting an existing boiler to one which utilizes the fuel from a gasification/desulfurization system depends on a number of factors, many of which will differ from one boiler to the next. The space available for a gasification/desulfurization system in an existing power plant, the modifications necessary to retrofit an existing boiler, and the performance of a retrofit boiler will depend on the specific gasification/desulfurization system design and choice of operating conditions, the location of the gasification/desulfurization system in the plant, the type of boiler (coal- or oil-fired), size of boiler, the turn-down needed, the boiler load factor, and the specific design features of the boiler. These factors are discussed with respect to the location of the gasification/desulfurization system relative to the boiler, and the importance of boiler performance in a retrofit boiler.

The gasification system may be placed internal to the boiler (directly beneath) or external to the boiler (as close as possible without carrying out major boiler modifications in order to locate the system). These concepts are illustrated in Figure 40.

Using the criterion that the internal design is feasible if the boiler cross-section is larger than the gasifier cross-section leads to the conclusions in the following list of retrofit design factors:

Critical Factors in Determining Feasibility of Internal Retrofit Design -- Regenerative or Once-through
- Superficial Velocity
- Air/Fuel Ratio
- Temperature Control Method
- Boiler Type (Coal or Oil) and Size

Feasibility Limits on the Internal Retrofit -- Based on Boiler Capacity > 100 MW
- Superficial Velocity $\geq$ 8 ft/sec
- Air/Fuel Ratio $\leq$ 20% of Stoichiometric
- Temperature Control by Minimum Air/Fuel Ratio and Heat Transfer Surface Feasible for Boilers > 100 MW
- Temperature Control by Stack Gas Recycle, Steam and Water Injection Feasible for Boilers < 200 MW
- Internal Design More Probable With Coal- than with Oil-fired Boilers

Dwg. 2947A66

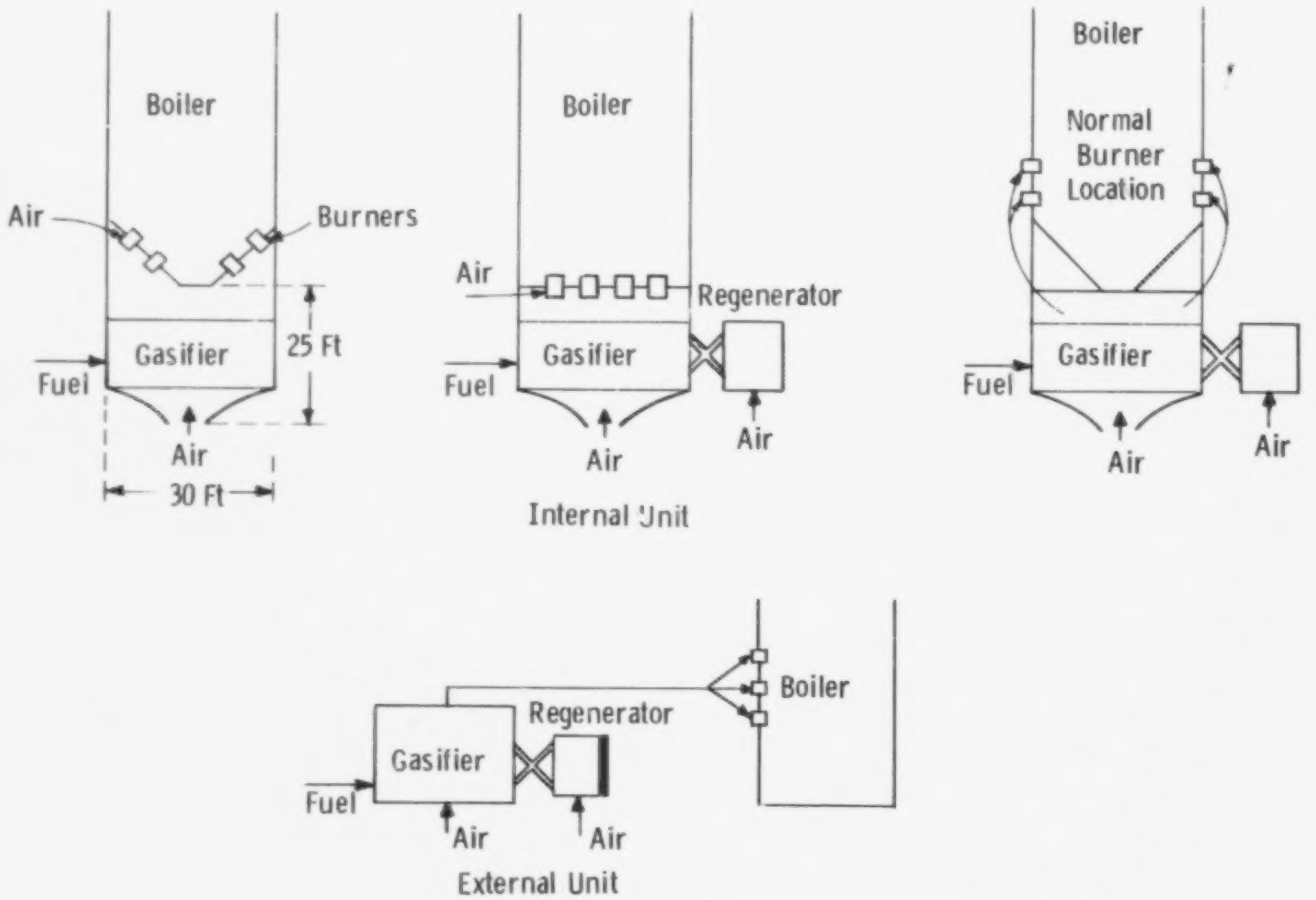


Fig. 40—Boiler add-on concepts

The lists of retrofit factors on the next two pages summarize the points affecting the feasibility of boiler retrofits. The first compares the internal and the external location of the gasification/desulfurization system, while the second compares the modifications and boiler performance probable with coal- and oil-fired retrofits.

The factors presented in both lists seem to favor the external retrofit design over the internal retrofit design, and the feasibility of retrofitting a coal-fired boiler over the feasibility of retrofitting an oil-fired boiler. However, these preliminary investigations do not eliminate the possibility of the internal retrofit design or the retrofit of oil-fired boilers.

In contrast to boiler retrofit considerations, the feasibility of incorporating a gasification/desulfurization system into a new boiler design will be limited only by the overall economics of the system and the market potential for new oil-fired boilers. The total space occupied by the gasification/desulfurization system will be a small percentage of the total plant volume. Also, because of the flexibility in boiler design, boiler performance will not be affected by the presence of the gasification/desulfurization system.

Market studies indicate that the number of new oil-fired boilers which will be constructed will decrease, with practically no new oil-fired boilers being constructed after 1980(16). Based on this projection, the gasification/desulfurization of residual oil will be limited to the retrofit of existing boilers, regardless of the system economics. Further investigation of the market potential of the new boiler system is needed.

ECONOMICS

Table 29 lists the preliminary cost breakdown for the major equipment included in a 600 MW regenerative retrofit and a new system. Total investment is indicated for each of the five proposed temperature control methods in $/kW. The cases of boiler retrofit with and without

GASIFIER RETROFIT LOCATION FACTORS

Internal Location	External Location
Space Requirements	
Under suitable operating conditions space available beneath the boiler may be utilized (Table 6-16). The cross-sectional area needed to place burners in the upshot position at the base of the boiler may limit the concept (new burners may be 1.5-3 times the size of normal oil or coal burners). Design if limited by the available overhead space if particulate control is needed before burners. Probably not feasible with modular design in large boilers (> 500 MW) except at velocities >> 8 ft/sec.	Space must be found or provided as near to the boiler as possible. More flexibility which is present in the external design may allow operating with maximum fuel heating value to minimize burner sizes. Feasibility not as limited by the space required for modular design, overhead space, or other spatial considerations.
Modification Factor	
More extensive modifications required, more down time, involved in removal of ash pit, auxiliary equipment, alterations to water walls and foundations. Construction more expensive in comfined quarters beneath boiler. The amount of piping and manifolding may be minimized with burners placed in the base of the boiler. Each boiler retrofit design may need to be treated as a unique case.	Modifications consist of removal of auxiliary equipment, such as pulverizers, and addition of new burners. Prefabrication of vessels possible. Relatively great amount of high temperature, noncorrosive, piping and manifolding necessary, though the same may be true with internal design. More uniformity in design from one retrofit to another.

GASIFIER RETROFIT LOCATION FACTORS (Continued)

Internal Location	External Location
Performance Factor	
The need for operating conditions giving maximum gasifier compactness may be detrimental to the system performance.	Greater flexibility in the operating conditions which is present with external design may allow operation at under optimum conditions.

RETROFIT OF COAL-AND OIL-FIRED BOILERS

Space Requirements

Coal-fired boilers have larger cross-sections than oil-fired boilers at large capacity (> 100 MW)

Cross-sections are comparable for smaller capacity boilers (< 100 MW)

Headroom is nearly the same in coal-and oil-fired boilers at 12-25 feet.

More potential space exists near a coal-fired boiler than near an oil-fired boiler - pulverizers and other auxiliary equipment may be removed - especially advantageous if the coal boiler has been previously converted to operate with low-sulfur oil.

Modification Factors

Normal coal and oil burners are nearly the same size (200 MW Btu/hr burner is 10-11 ft^2 in port cross-section).

Much solid handling equipment and particulate clean-up equipment may already exist with a coal-fired boiler. Increased particulate control would probably be needed with an oil-fired boiler.

Performance Factors

Coal-fired boilers are designed to operate with slag on the boiler heat transfer surface, which may make boiler derate negligible with coal-fired boilers. Boiler derate may be important with oil-fired boilers depending on the gasifier temperature control method.

TABLE 29

REGENERATIVE OPERATION CAPITAL COSTS - 600 MW

EQUIPMENT x 10^{-3} $	TEMPERATURE CONTROL METHOD				
	Heat Transfer Surface	Minimum Air/Fuel	Stack Gas Recycle	Steam Injection	Water Injection
Gasifier	1,020[a]	310	850	870	560
Regenerator[b]	135	135	138	144	140
Limestone Handling	1,225	1,225	1,235	1,315	1,260
Fans	300	200	400	400	300
Burners	720	610	900	890	780
Particulate Clean-up[c]	1,620	1,510	2,030	1,980	1,760
Boiler Modifications	900	900	900	900	900
Equipment	5,920	4,890	6,453	6,499	5,700
Installation	2,960	2,445	3,227	3,250	2,850
Direct Cost	8,880	7,335	9,680	9,749	8,550
Eng., Cont., Const.	2,660	2,200	2,910	2,930	2,570
Sulfur Recovery	3,300	3,300	3,340	3,540	3,440
Total Investment	14,840	12,835	15,930	16,219	14,560
Retrofit $/kW	24.7	21.4	26.6	27.0	24.2
Retrofit $/kW (without particulate control)	19.5	16.5	20.0	20.6	18.6
New $/kW (without particulate control)	14.3	11.6	14.2	14.8	13.1

(a) Gasifier cost doubled to include heat transfer requirement.

(b) Regenerator temp. control by heat transfer surface - doubles vessel cost.

(c) Particulate clean-up includes cyclones prior to burners and electrostatic precipitator final clean-up.

the cost of particulate control equipment (cyclones prior to combustion and electrostatic precipitator final clean-up) are included, along with the estimated cost for the regenerative gasifier/desulfurization system when combined with a new boiler design.

Table 30 summarizes operating costs for a 600 MW regenerative operation (new and retrofit) with an 80% load factor. The case of retrofit with a 40% load factor is included to show the effect of this important variable on the system operating cost.

The three most important factors in determining the economics of the regenerative operation are: the carbon deposition rate; the air/fuel ratio; and the overall system efficiency.

The capital cost breakdown for 600 MW once-through operation, new and retrofit, is summarized in Table 31. Temperature control by heat transfer surface, minimum air/fuel ratio, and stack gas recycle are considered, and the total capital investment in $/kW is shown for retrofits with and without particulate control, and for a new boiler excluding the cost of particulate control.

Operating costs, in ¢/10^6 Btu, are shown in Table 32 for the three temperature control schemes. Both 80% and 40% load factors are considered in the table, and the results for retrofits and new designs are shown.

With once-through operation, the air/fuel ratio controls the equipment sizes and the particulate clean-up costs and affects the system efficiency. The overall efficiency determines the direct fuel adder cost, but the rate of carbon deposition plays a much less important part in the system economics.

EVALUATION

The regenerative and once-through modes of operation have been compared, and the merits and disadvantages of each mode have been considered. The costs and pollution control potential of residual oil

TABLE 30

OPERATING COSTS FOR REGENERATIVE OPERATION - 600 MW, 80% LOAD FACTOR

	Heat Transfer Surface	Minimum Air/Fuel	Stack Gas Recycle	Steam Injection	Water Injection
Capital Charges 10^3 \$/yr [(a)]	1620	1340	1770	1780	1560
Maintenance[(a)]	580	480	630	640	560
Overhead(a)	460	380	510	510	450
Limestone (2.5/ton)	278	278	280	296	284
Disposal (\$1.30/ton)	145	145	146	154	148
Sulfur Recovery	1210	1210	1210	1270	1240
Fuel Adder (\$3/bbl) [(b)]	928	855	1010	2940	1580
	5221	4688	5556	7590	5822
Retrofit Fuel Adder,[(c)] ¢/10^6 Btu (80% Load Factor)	12.4	11.2	13.2	18.1	13.9
(40% Load Factor)	18.8	16.4	20.1	25.0	20.0
New Design Fuel Adder, ¢/10^6 Btu (80% Load Factor)	10.7	9.5	11.1	16.0	12.0

(a) Includes particulate control.
(b) Based on overall efficiency.
(c) No sulfur credit - credit would amount to about 1.5¢/10^6 Btu at \$15/ton of sulfur.

TABLE 31

ONCE-THROUGH OPERATION CAPITAL COSTS - 600 MW

EQUIPMENT x 10^{-3} \$	TEMPERATURE CONTROL METHOD		
	Heat Transfer Surface	Minimum Air/Fuel	Stack Gas Recycle
Gasifier	1,020	310	850
Sulfate Generator	188	188	188
Limestone Handling	1,320	1,320	1,330
Fans	300	300	400
Burners	720	610	900
Particulate Clean-up	1,820	1,710	2,230
Boiler Modifications	900	900	900
Equipment	6,268	5,338	6,798
Installation	3,134	2,669	3,399
Direct Cost	9,402	8,007	10,197
Eng., Cont., Const.	2,820	2,400	3,060
Total Investment	12,222	10,407	13,257
Retrofit, \$/kW	20.4	17.3	22.1
Retrofit, \$/kW (Without Particulate Control)	15.2	12.4	15.5
New, \$/kW (Without Particulate Control)	10.0	7.5	9.7

TABLE 32

OPERATING COSTS FOR ONCE-THROUGH OPERATION - 600 MW, 80% LOAD FACTOR

	Heat Transfer Surface	Minimum Air/Fuel	Stack Gas Recycle
Capital Charges 10^3 \$/yr (a)	1710	1460	1855
Maintenance (a)	610	520	665
Overhead (a)	490	420	530
Limestone (\$2.50/ton)	835	835	840
Disposal (\$1.30/ton)	435	435	435
Fuel Adder (\$3/bbl) (b)	830	740	928
	4910	4410	5253
Retrofit Fuel Adder ¢/10^6 Btu (80% Load Factor)	11.7	10.5	12.5
(40% Load Factor)	18.4	16.2	19.7
New Design Fuel Adder ¢/10^6 Btu (80% Load Factor)	9.9	8.9	10.4

(a) Includes particulate control.

(b) Based on overall efficiency.

gasification/desulfurization are compared with the low-sulfur oil and stack gas cleaning alternatives. In addition, preliminary design conclusions are listed to summarize the results of the technical feasibility studies.

Comparison Between Regenerative and Once-Through Operations

The relative merits of the two modes of operation are summarized on the following page. Preliminary investigations indicate that, overall, the once-through operations may be somewhat more attractive to a utility customer than the regenerative operation. Further research into the areas of sulfur recovery and system dynamics may alter this outlook.

Comparison With Other SO_2 Control Methods

A comparison is made in Table 33 between atmospheric pressure oil gasification/desulfurization and the alternative schemes of low-sulfur oil and stack gas cleaning. Capital costs and operating costs are compared for new and retrofit systems. Oil gasification/desulfurization compares favorably with low-sulfur oil and stack gas cleaning, based on the preliminary cost estimates presented in Tables 29 through 32. A reduction of about 40% in the capital costs involved in stack gas cleaning is estimated for new and retrofit gasification/desulfurization systems. Operating costs appear to be about the same for once-through stack gas cleaning and regenerative gasification/desulfurization with sulfur recovery. Once-through gasification/desulfurization may reduce the operating costs 30 to 50% as compared to stack gas cleaning. The cost estimate indicates that the operating cost with low-sulfur fuel oil will be about 20% greater than the operating cost for gasification/desulfurization. These conclusions are based on the desulfurization of high-sulfur residual oil (3 wt. % sulfur) and may be altered when a lower sulfur oil is considered (1 to 1.5 wt. % sulfur). Environmental factors are also compared in Table 23. The low-sulfur oil is advantageous in that capital costs are limited to possible boiler

COMPARISON BETWEEN MODES OF OPERATION

ECONOMICS

Once-through operation requires lowest capital investment.

Operating costs are nearly identical for once-through and regenerative operations (mainly because of the high cost associated with sulfur recovery).

Sulfur credit does not greatly reduce the operating cost of a regenerative operation.

SPACE REQUIREMENTS

Both modes have the same potential equipment sizes, though the regenerative operation requires a large space for sulfur recovery making the once-through more compact in an overall sense.

Once-through may require deeper gasifier bed depth and larger limestone handling equipment.

PERFORMANCE

Both modes have same potential for sulfur removal.

Once-through may be slightly more efficient than regenerative.

Once-through has higher power requirements.

Once-through thermal efficiency is independent of carbon deposition rate.

Regenerative operation minimizes stone disposal rate.

Once-through presently has fewer technical problems.

UTILITY REACTION FACTORS

Regenerative mode puts utility in the chemical business.

Once-through is the simplest mode of operation, but may increase solid waste problem unless high stone utilization can be achieved.

TABLE 33

ASSESSMENT OF FLUIDIZED BED OIL GASIFICATION-DESULFURIZATION

Basis: 3% Sulfur, 90% Sulfur Removal, 600 MW Capacity

			Oil Gasification	
	Low-Sulfur Oil	Stack Gas Cleaning	Regenerative Operation	Once-Through Operation
COST				
Capital, $/kW				
New	---	25	12-15(b)	8-10(b)
Retrofit	(a)	40-75	22-27(b)	18-22(b)
Fuel Adder, ¢/10^6 Btu				
New	17-23	11	9.5-16.0(b)	9-10.5(b)
Retrofit	17-23(a)	14-20	11-18(b)	10.5-12.5(b)
EFFICIENCY	---	0.95-0.98	0.89-0.96(c)	0.96-0.97(c)
ENVIRONMENTAL FACTORS				
SO_2, ppm (lb/10^6 Btu)	80-100 (0.35)	100-110 (0.45)	80-100 (0.35)	80-100 (0.35)
NO_x, ppm (lb NO_2/10^6 Btu)	200-400 (0.40)	400-700 (0.8)	100-150 (0.16)	100-150 (0.16)
Particulates, gr/SCF (lb/10^6 Btu)	0.03 (0.06)	0.03 (0.05)	0.01-0.10(d) (0.02-0.2)	0.01-0.10(d) (0.02-0.2)
Solid Waste, ft^3/MW-day	---	25	15	45
S REMOVAL				
Stone	NA		Limestone	Limestone
Ca/S	NA		∿ 15 (e)	3.0
Make-up Ca/S	NA		1.0	NA

(a) Equipment modifications are required when converting from gas or coal to low sulfur oil.
(b) See Tables 29 through 32 for details.
(c) Overall efficiency is dependent on mode of temperature control.
(d) 0.01 figure based on installing electrostatic precipitator (ESP).
0.1 figure based on installing high efficiency cyclone before burners and no ESP.
(e) Ca/S rated dependent on regenerator temperature control scheme.

modifications necessary when changing from gas or coal to low-sulfur oil. On the other hand, operating costs are higher than those for stack gas cleaning or oil gasification/desulfurization. Capital costs are extremely high with stack gas cleaning, especially in the retrofit case, while operating costs are very near those estimated for oil gasification/desulfurization.

Preliminary design conclusions based on the technical investigations carried out are listed below. Though the analysis has raised many technical questions, the preliminary investigation, coupled with the experimental work of Esso, England, points out the general feasibility of oil gasification/desulfurization as a retrofit SO_2 control system for utility boilers.

PRELIMINARY DESIGN CONCLUSIONS

TECHNICAL PROBLEM AREAS

Sulfur recovery
Boiler derate and boiler modifications
Calcium sulfate generation
Temperature control
Lime circulation

CURRENT OUTLOOK

Overall, once-through operation appears superior to regenerative if high stone utilization can be achieved though this is not definite (Table 33).

Gasifier temperature control by means of the minimum air/fuel ratio appears superior to other methods, if it can be achieved in practice. Temperature control with heat transfer surface also may be attractive if high air/fuel ratios ($\geq$ 20%) must be used in operation.

The regenerator temperature control is best carried out by stone circulation if carbon deposition is small. If carbon deposition is large, then heat transfer surface is the most efficient method.

Sulfate generator temperature control is most easily carried out by circulating excess air through the generator.

The situation concerning the internal and external design concept is not clear (page 154) with the number of variable factors which are involved. It seems reasonable to strive to minimize the expense and time involved in boiler modifications.

The greatest market for oil gasification/desulfurization appears to be in retrofits at the present time. The problems involved with retrofits should be examined in more detail.

Oil gasification/desulfurization concepts appear highly competitive with other retrofit or new SO_2 control methods based on preliminary designs (Table 33), and should be investigated in greater detail (see Recommendations).

FLUIDIZED BED FUEL PROCESSING DEVELOPMENT PLANTS

Conceptual designs, costs, and schedules for a 10 to 30 MW pressurized fluidized bed combustion boiler development plant and a 100 to 200 MW retrofit atmospheric pressure oil gasification demonstration plant have been prepared.

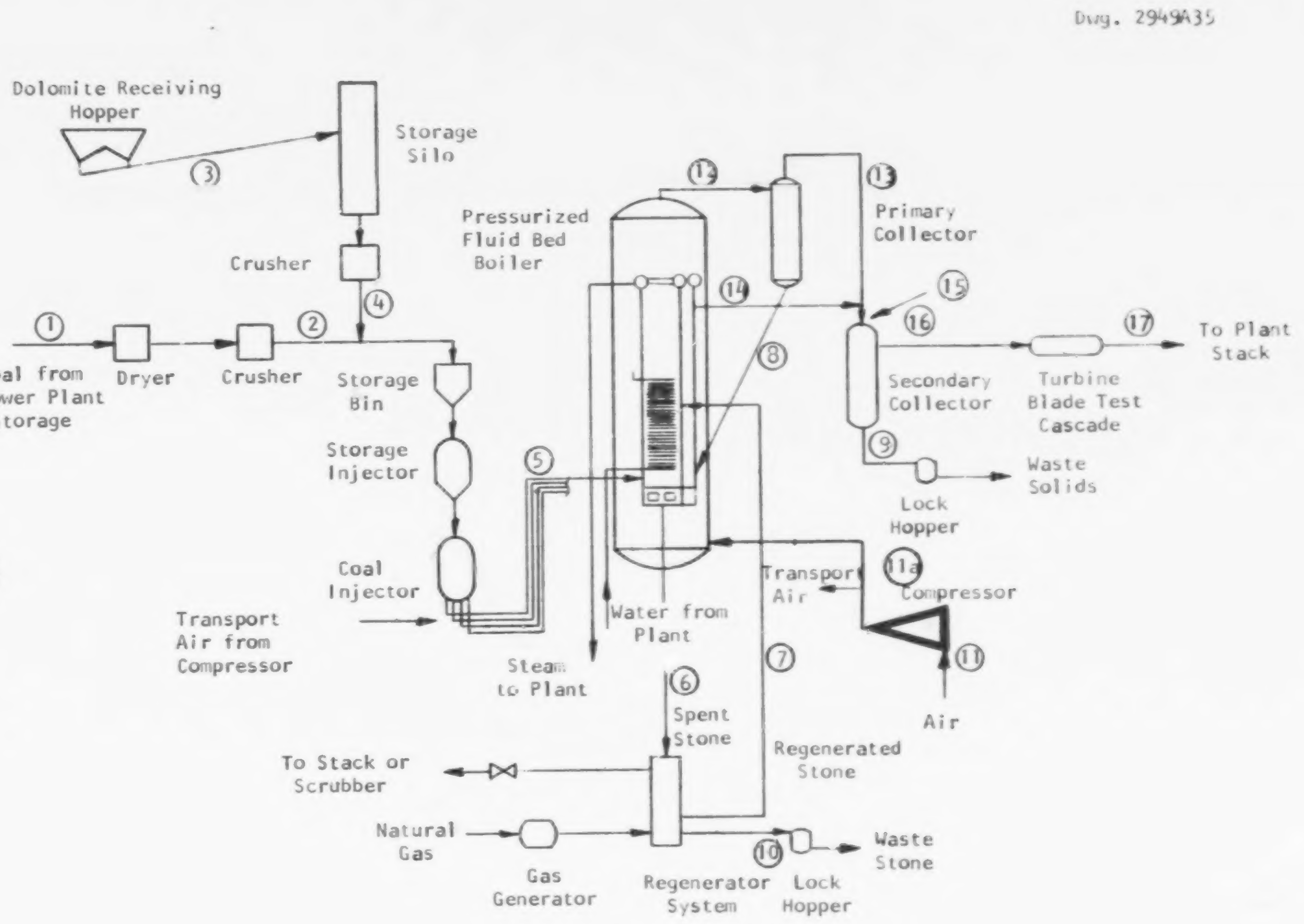
PRESSURIZED FLUID BED COMBUSTION BOILER DEVELOPMENT PLANT

The development plant is designed to provide information which will permit the construction of a 150 to 300 MW demonstration power plant. The development plant is required to provide information on the performance of the proposed boiler plant equipment design:

- Operation of deep beds (10 to 20 ft) with horizontal tube bundles
- Particulate removal
- Coal and sorbent handling and feeding systems
- Materials and component life - boiler tubes and gas turbine blades
- Operation - start-up, shut-down, load follow
- Regeneration/sulfur recovery process demonstration.

A flow diagram of the pressurized fluid bed combination boiler development plant is shown in Figure 41. The plant is located adjacent to a large power plant and has access to the power plant to provide interfaces with the coal, water, steam, waste stone, and utilities. The facility is designed to operate over the following range of operating conditions:

Pressure	up to 20 atm
Bed Temperature	1300-2000°F
Gas Velocity	6-15 fps
Bed Depth	10-30 ft



Location: Existing Power Plant

Fig. 41 —Flow diagram for development plant facility

The boiler is designed to handle up to 500,000 lb/hr of steam flow. The unit would function as either a pre-evaporator, superheater, or reheater. Water evaporation in the walls could also be studied.

The boiler is a single fluidized bed with a carbon burn-up cell. The design is based on the proposed design by Westinghouse and Foster Wheeler. The water-walled, fluidized bed boiler would be placed in a pressure shell which would be larger than required for commercial operation. A vessel 15 to 20 feet in diameter and 50 to 70 feet high is projected. This will permit easy access, flexibility for modifications, and functioning over a wide range of operating conditions.

Coal receiving equipment and storage is assumed to be available from the power plant. Coal and dolomite handling equipment specified for the development plant include a dolomite receiving hopper, dolomite storage silo, dolomite crusher, coal dryer, and coal crusher. The coal feed system and particulate removal equipment are the same as the proposed design. The air compressor is independent of the gas turbine test system. Initial gas turbine tests will be carried out with a turbine blade test cascade. The second phase of operation includes a rotating gas turbine unit. The two-step regeneration process is specified in the present design concept.

The development plant program is broken down into three phases of operation:

Phase I - Operation of fluid bed boiler with turbine blade test cascade and without sorbent regeneration process
Phase II - Operation of integrated system, including gas turbine and regeneration process
Phase III - Operation to evaluate alternative concepts, e.g., regeneration processes, bed design, steam conditions.

The first phase would provide information to assess the proposed design concept -- boiler and carbon burn-up cell.

The second-phase operation would incorporate design modifications recommended from the analysis of Phase I data, and the parallel research and development efforts include a regeneration process and a small gas turbine unit. A sulfur recovery process should also be considered if development effort is required.

The third-phase operation would be used to assess alternative concepts. Development of the third-phase program will rely on the results of the analysis of data from Phases I and II, results of pilot and bench scale experimental programs, and recommendations from systems evaluation and advanced concept studies. This phase might include the evaluation of higher gas turbine temperatures, higher steam temperatures and pressures, alternative regeneration/sulfur recovery processes, and circulating bed boiler concepts.

The estimate for the development plant equipment, installed out-of-doors adjacent to a large central station power plant, is $7,000,000.

A development plant schedule has been prepared and is presented in Figure 42. The projected time required to assess the combustor design, develop a regenerator process, and obtain data on turbine blade performance is four years. The plant could then be used to study alternative boiler and regeneration system concepts.

ATMOSPHERIC PRESSURE OIL GASIFICATION DEMONSTRATION PLANT

The economics of a utility boiler retrofit system appear competitive with wet scrubbing systems and with the purchase of clean fuel. Demonstration plant concept designs were reviewed in a previous section.

A demonstration plant with a capacity of 100 to 200 MW is the best size from the standpoint of being representative of the boiler retrofit market while minimizing the scale-up factor. For boiler sizes less than about 80 MW, the overall boiler design differs greatly from that of boilers in the 100 to 800 MW range. The 100 to 200 MW capacity boiler

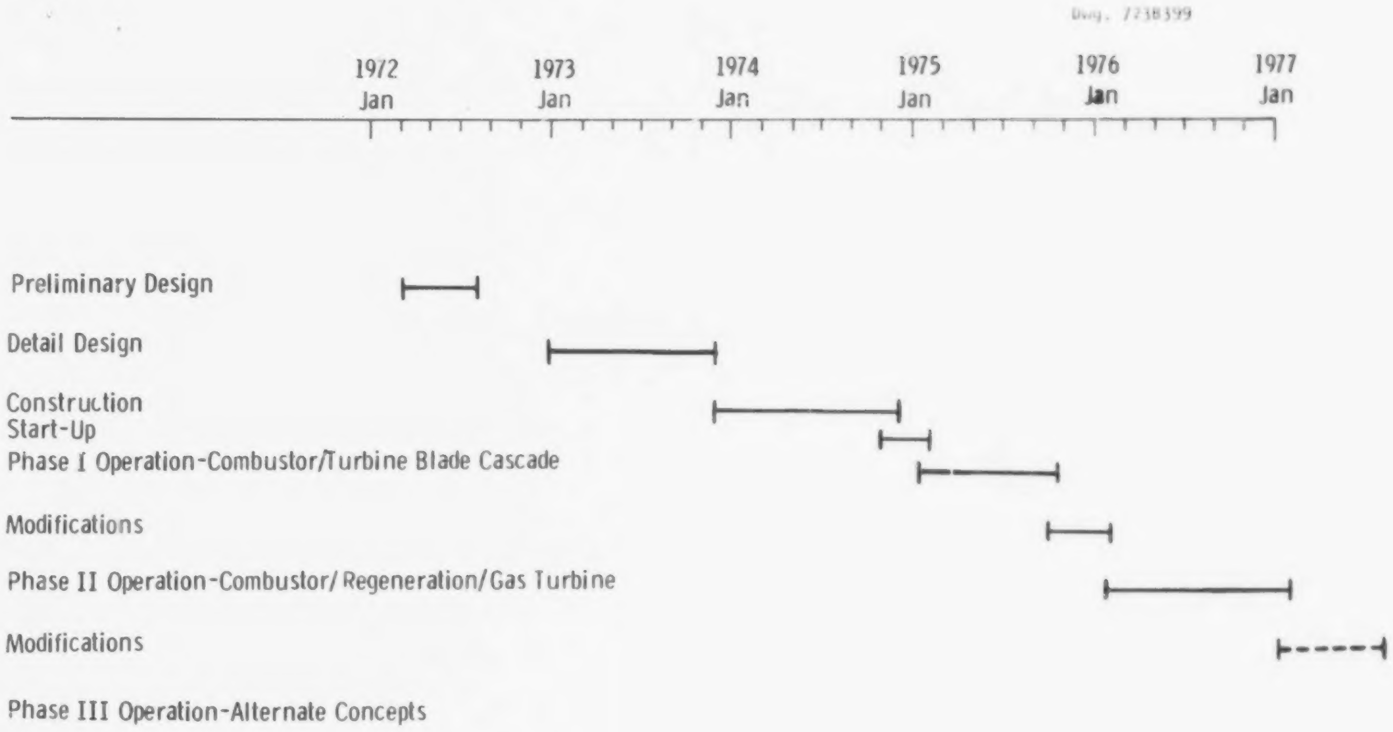


Fig. 42 — 10-30 MW pressurized fluid bed boiler development plant schedule

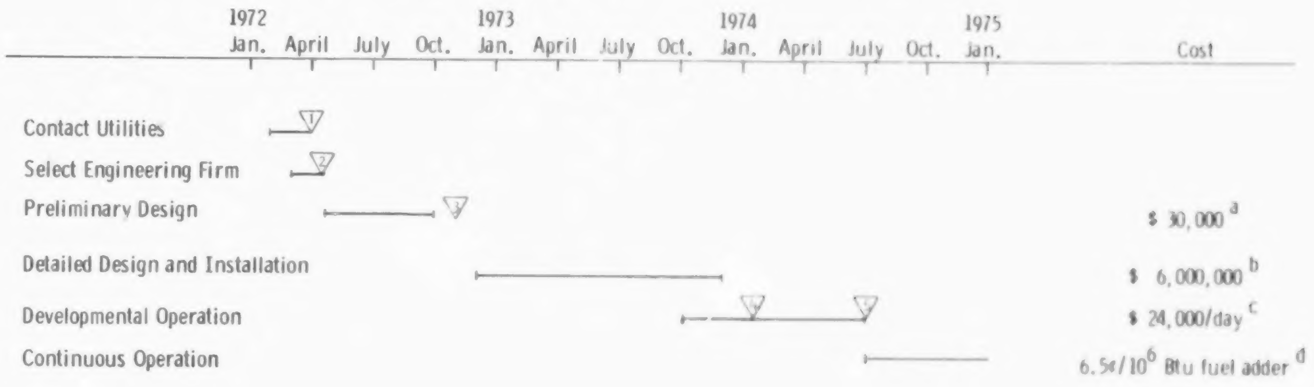
may also be more available than a smaller capacity unit. Although the scale-up from the ~1 MW pilot plant unit of Esso, England, to a 100 to 200 MW system is considerable, this represents the minimum scale-up factor which will give meaningful demonstration results within the next five years.

The cost of the installed equipment for a 200 MW demonstration plant is estimated to be $6,000,000. If the plant includes a sulfur recovery system, the cost would be approximately $8,000,000.

The schedule for an atmospheric pressure oil gasification demonstration plant is shown in Figure 43.

FIG. 43—DEMONSTRATION PLANT SCHEDULE

Atmospheric Oil Gasification/Desulfurization Process for Existing Steam Power Plants



Milestones

- ▽1 Cooperating utility identified
- ▽2 Engineering firm contract signed for preliminary design
- ▽3 Decision on construction; agreement between OAP - utility - ♆ - AE
- ▽4 Shake down complete
- ▽5 Engineering and economic data for future operations complete

Footnotes

- a Cost estimate for preliminary design
- b Assumes complete 100 MW gasifier module, once-through limestone system
- c Maximum cost per day assumes continuous oil feed, O & M for gasifier development, and no power generation
- d Based on conceptual design

CONCLUSIONS

FLUIDIZED BED COMBUSTION BOILERS

Boiler Design

The following operating and design characteristics are required for economical design:

- Standardized modules with maximum shop fabrication
- High gas velocities, 8 to 15 fps
- Large coal and limestone/dolomite, 1/8-1/4 inch top size

Boiler Performance

Laboratory and pilot scale tests have produced essential information in a number of critical subject areas:

- Sulfur dioxide: 80 to 95% sulfur removal has been demonstrated with limestone and dolomite.
- Nitrogen oxides: atmospheric pressure two-stage combustion has reduced NO_x to about 70 ppm; pressurized single-stage combustion has reduced NO_x to 50-150 ppm.
- Particulates: particulate loading is comparable with conventional plants. Fine particulate (< 10 μm) emissions may be significantly reduced compared with p.f. coal-fired plants.
- Combustible losses: combustible losses can be minimized by collecting high carbon content solids from primary beds and recovering the energy in a carbon burn-up cell.
- Ash fouling: reduced ash corrosion, erosion, and fouling may increase boiler availability.

Preceding page blank

Industrial Fluidized Bed Combustion Boilers

Market

- Industrial boilers will probably continue to use clean fuels as long as these are available.
- Limestone regeneration/sulfur recovery on-site is not considered practical.

Economics

- Fluidized bed industrial boiler cost estimates do not show significant (> 10%) cost advantages over conventional coal-fired boilers with SO_2 control.
- Gas- or oil-fired fluidized bed boilers are not economical in comparison with conventional packaged boilers.
- Fluidized bed boilers are economical for burning low-sulfur char or other low-grade fuels.

Utility Fluidized Bed Combustion Boilers

Market

- The market for fossil fuel power plants is ~30 gigawatts/yr; the most frequently installed plant capacity is about 600 megawatts.
- Coal reserves provide a 200 to 500 year supply.
- Both plants with once-through operation and those with sulfur recovery have potential markets, depending on plant capacity, fuel, and location.

Economics Compared with a Conventional Pulverized Fuel Power Plant with Stack Gas Cleaning

- Capital cost savings for atmospheric pressure plants may be 7% for a sulfur recovery system, 12% for a once-through system.
- Capital cost savings for pressurized combined cycle plants may be 18% for a sulfur recovery system, 21% for a once-through system.

- Energy cost reduction for atmospheric pressure plants may be 2 to 7%.
- Energy cost reduction for pressurized combined cycle plants may be 10 to 12%.

Performance

- Pressurized combined cycle plants show greater pollution abatement.
- Pressurized combined cycle plants have greater efficiency.

Development Status

- The time and effort devoted to atmospheric pressure fluidized bed combustion has been an order of magnitude greater than that devoted to pressurized. However, the technical accomplishments appear comparable.
- Both atmospheric and pressurized fluidized bed power systems require further development effort. Data can be most rapidly and economically acquired on development-scale equipment -- e.g., coal feeding, NO_x minimization, and control for both atmospheric and pressure operation; deep beds, particulate removal, gas turbine blade performance for pressurized operation.

Potential

- No problems have been identified which would preclude the development of fluidized bed combustion boilers.
- Potential improvements in a second generation of boilers for utility applications include raising steam temperature and pressure above the present maximums -- 1050°F, 3500 psi. Pressurized combined cycle plants have the potential for further reduction of heat rate by going to higher gas turbine temperatures.
- Low-grade fuels can be burned.

ATMOSPHERIC PRESSURE FLUIDIZED BED OIL GASIFICATION

Market

- New oil-fired electric utility installations during 1971 through 1980 are projected to be 6.2 gigawatts.
- Oil utilization by electric utilities beyond 1980 should be surveyed.
- Initial market is expected to be small boilers (< 600 MW) on the East Coast, in the Southwest where gas may be limited, or on the West Coast. Once-through operation is favored over operation with sulfur recovery for these plants.

Economics for Comparable Pollution Abatement

- Capital cost of a retrofit, once-through gasification system may be 50 to 70% less than a retrofit wet scrubbing system.
- Capital cost of new gasification systems (once-through or sulfur recovery) may be 20 to 50% less than a new wet scrubbing system. Total plant cost savings may be 1 to 4%.
- Fuel adder cost for a retrofit, once-through gasification system may be 30 to 50%* less than wet scrubbing, low-sulfur oil, or desulfurized oil.
- Fuel adder cost for new gasification systems (once-through or sulfur recovery, without a sulfur credit) may be 20 to 30% less than wet scrubbing, low-sulfur oil, or desulfurized oil. Total energy cost savings may be 1 to 3%.
- Calcium oxide produced in the gasification concept may be a valuable by-product for use in wet scrubbing systems, which may be used in near-by plants.

Performance

- Sulfur removal up to 95% can be achieved.
- Nitrogen oxide emissions of 150 ppm appear possible.

---

*Based on $2.50/ton limestone.

- Particulate emissions will be higher than conventional oil-fired systems but can easily be removed to achieve proposed standards.
- Solid waste will be dry and comparable in quantity to wet scrubbing waste.
- Overall efficiency is comparable to wet scrubbing.
- Reliability of plant may be increased with the gasification system due to reduction in SO_3, vanadium, and sodium before the boiler.

Development Status

- The concept has been technically demonstrated with a 750 kW development gasification plant.
- No problems have been identified which preclude the development of atmospheric pressure oil gasification.
- Further development effort is required in key areas -- e.g., calcium sulfate generation for once-through operation, temperature control, sulfur recovery.

RECOMMENDATIONS

INDUSTRIAL FLUIDIZED BED COMBUSTION BOILERS

Fluidized boilers for industrial application do not have significant overall cost and performance advantages over conventional coal-fired boilers with pollution control. Based on the market projections for clean fuel for industrial boilers and the technical assessment, we recommend that

- Further development work on industrial fluidized bed boilers be deferred until future availability of clean fuel can be assessed.
- Fuel usage for industrial boilers be monitored to determine any change from the use of clean fuels
- Development of industrial fluidized bed boilers be reassessed if low-sulfur char or alternate low-sulfur, low-grade fuels become available.

UTILITY FLUIDIZED BED COMBUSTION BOILERS

Pressurized fluidized bed power plants show greater pollution abatement, lower costs, and greater development potential than atmospheric pressure fluidized bed or conventional pulverized fuel plants. Based on the projected market for coal and the technical assessment, we recommend that

- Emphasis be placed on the development of pressurized fluidized bed power plants
- Advanced concepts, generation, and evaluation be conducted to produce improved power plant designs

Preceding page blank

- Detail design of a 10 to 30 MW pressurized fluidized bed boiler development plant be initiated, based on bench and pilot plant data.
- Laboratory research and development on pressurized fluidized bed combustion be continued in key areas -- sulfur removal, NO_x reduction, stone regeneration, sulfur recovery, materials evaluation, advanced concepts.

ATMOSPHERIC PRESSURE OIL GASIFICATION

The performance and cost for a utility boiler add-on system are competitive with stack gas cleaning and with the purchase of clean oil. Based on this technical assessment, we recommend that

- The market for oil beyond 1975-1980 for power generation be scrutinized in order to assess the market potential for atmospheric and pressurized oil gasification
- Utilities be contacted and a utility partner be identified for a demonstration installation of an add-on oil gasification unit
- A preliminary design of the demonstration plant be prepared
- Research and development work be continued in key areas -- e.g., carbon deposition, temperature control, load range, sulfur recovery, pressurized operation.

REFERENCES

1. Godel, A. and P. Cosar, "The Scale-up of a Fluidized Bed Combustion System to Utility Boilers", paper presented at Chicago AIChE Meeting, Nov. 1970 (CEP Fluidization Sym. Series Vol. 67, No. 116, 1971).

2. Demmy, R. H., "Ignifluid Boilers for an Electric Utility", paper presented at Second International Conference on Fluidized Bed Combustion, Hueston Woods, Ohio, Oct. 4-7, 1970.

3. Hanway, J. E., "The Use of Fluidized Bed Technology in Pollution Control", paper presented at Chicago AIChE Meeting, Nov., 1970 (CEP Fluidization Sym. Series Vol. 67, No. 116, 1971).

4. Blanc, H. and M. Maulaz, "Sludge Press Cake Incineration in a Fluosolid Oven", Proceedings of 1970 National Incinerator Conference, p. 107.

5. Bailie, R. C., D. M. Donner, and A. S. Galli, "Potential Advantages of Incineration in Fluidized Beds", Proceedings of 1968 National Incinerator Conference, p. 12.

6. "Combustion Power Unit-400", Interim Progress Report on Contract No. Ph 86-67-259, BSWM, 1969.

7. Reid, W. T., "External Corrosion and Deposits-Boilers and Gas Turbines", Elsevier, New York, 1971.

8. Second Annual Lime/Limestone Wet Scrubbing Symposium, New Orleans, La., Nov. 8-12, 1971.

9. See Volume II.

10. Archer, D. H., D. L. Keairns, and W. C. Yang, "Marketable Designs for Fluidized Combustion Boilers", paper presented at Second International Conference on Fluidized Bed Combustion, Hueston Woods, Ohio, October 1970.

11. Volumes II and III.

12. Keairns, D. L. and D. H. Archer, "Fluidized Bed Boilers - Concepts and Comparisons", paper presented at Second International Conference on Fluidized Bed Combustion, Hueston Woods, Ohio, October, 1970.

13. Hoy, H. R. and J. E. Stantan, American Chemical Society, Div. of Fuel Chem. Prepr. 14, (2), 59 (May 1970).

14. Bryers, R. W., "Design Features of a Pressurized Fluidized Bed Boiler", paper presented at Second International Conference on Fluidized Bed Combustion, Hueston Woods, Ohio, October, 1970.

15. Discussions with the British National Coal Board.

16. Hauser, L. G., "Optimum Uses of Energy Sources", paper presented at Spring Conference, Southeastern Electric Exchange, New Orleans, La., April 1971.

ACKNOWLEDGMENTS

The results, conclusions, and recommendations presented in this report represent the combined work and thought of many persons at Westinghouse, at the Office of Air Programs (OAP), and elsewhere. Westinghouse personnel in many divisions throughout the Corporation have contributed. Our subcontractors -- Erie City, Foster Wheeler, and United Engineers and Constructors -- have added their expertise in boiler and power plant designs. Other OAP contractors have freely shared with us their ideas and the results of their research and development effort. Suppliers of boiler and power plant auxiliary equipment have discussed with us their products and provided cost estimates. Other commercial firms with background in fluidized bed technology have received us, shown us their work, and commented on ours. We have attempted to recollect all these contributions and what is undoubtedly (and regrettably) a partial list of organizations and persons is presented on the following pages.

In particular, however, we want here to express our high regard for and acknowledge the contribution of the personnel at OAP who conceived the overall fluidized bed combustion boiler effort and who have defined, monitored, and supported the efforts of Westinghouse and others on the program. Mr. P. P. Turner, Chief of the Advanced Process Section, has served as project officer on our work. Numerous enlightening and helpful discussions have been held with Mr. Turner; with section members D. Bruce Henschel and Sam Rakes; and with R. P. Hangebrauck, Chief of the Demonstration Projects Branch.

The following organizations and groups acted as subcontractors:

Foster Wheeler Corporation	• Assisted in evaluating utility fluidized bed boiler design concepts • Prepared preliminary designs of preferred concepts • Prepared cost estimates	R. W. Bryers J. D. Shenker R. Zoschak
United Engineers and Constructors Inc.	• Prepared plant layout, operating procedure, and plant cost for a pressurized fluidized bed combined cycle plant	M. Casapis E. Berman W. Craig J. Crowley
Erie City Energy, Division of Zurn Industries	• Compiled industrial boiler market survey • Assisted in evaluating industrial fluidized bed boiler design concepts • Prepared preliminary design of preferred concept • Prepared cost estimate	R. V. Seibel W. Schwinden
Westinghouse Divisions		
Heat Transfer	• Prepared cost estimates for regeneration system vessels and stack gas coolers	R. Giardina S. Jamison
Small Steam and Gas Turbine	• Prepared design and cost estimate for external combustor gas turbine	R. E. Strong B. Hugoson
Power Systems Generation Planning	• Prepared utility market survey • Provided power system cycle analyses	S. J. Jack R. R. Boyle R. J. Budenholzer H. L. Smith N. Weeks
Computer and Instrumentation	• Prepared control system design and cost for industrial boiler	R. Gessford

Sturtevant	• Supplied design and cost data for forced and induced draft fans	R. Mercer W. F. Courtney
Large Turbine	• Supplied cost information on steam turbines	

The following vendors supplied information and cost estimates:

Aerodyne Development Corporation	• Supplied design and cost information for high efficiency particulate removal equipment
Petrocarb, Inc.	• Supplied design and cost information for pressurized solids feeding systems
McNally-Pittsburg Manufacturing Corporation	• Supplied design and cost information for solids handling systems
Struthers Nuclear and Process Company	• Submitted proposal for stack gas coolers
Ducon Company, Inc.	• Supplied cost information for particulate removal
Ford, Bacon, and Davis, Inc.	• Supplied cost estimates for sulfur recovery processes
Ralph M. Parsons Company	• Supplied cost estimates for sulfur recovery processes
Wheelabrator Corporation	• Supplied electrostatic precipitator cost
Buell Engineering Company, Inc.	• Supplied electrostatic precipitator cost
Koppers Company, Inc.	• Supplied design information on solids feeding systems

The following facilities were visited by Westinghouse personnel:

Argonne National Laboratory
Chicago, Illinois

The Badger Company, Inc.
Boston, Massachusetts

Battelle Memorial Institute
Columbus, Ohio

Bituminous Coal Research
Monroeville, Pennsylvania

Chicago Bridge & Iron Company
Research Center
Plainfield, Illinois

Consolidation Coal Company
Pittsburgh, Pennsylvania

Dorr-Oliver Fluidized Bed
Sludge Incinerator
Liberty, New York

Esso Research and Engineering
Linden, New Jersey

Esso Petroleum Company
United Kingdom

Fluidized Bed Course
University of Birmingham, England

Fuller Company
Catasauqua, Pennsylvania

Kansas Power & Light
Topeka, Kansas

NAPCA/NCB Fluidized Bed Combustion Program
Second Information Exchange Meeting
Hobart House, London
BCURA, Leatherhead
CRE, Cheltenham

National Coal Board
United Kingdom

Pope, Evans & Robbins
Alexandria, Virginia

St. Joseph Lead Company
Monaca, Pennsylvania

Tennessee Valley Authority
Chattanooga, Tennessee

UGI Corporation
Kingston, Pennsylvania

Union Electric
St. Louis, Missouri

U.S. Bureau of Mines
Bruceton, Pennsylvania

U.S. Bureau of Mines
Morgantown, West Virginia

West Virginia University